Meeting Date: 12 May 2020

2020 Annual Assessment of Security of Supply

Security and Reliability Council

The Security of Supply Annual Assessment 2020, covering energy and capacity adequacy over a ten-year horizon

Note: This paper has been prepared for the purpose of the Security and Reliability Council. Content should not be interpreted as representing the views or policy of the Electricity Authority.

1. Background

The Security and Reliability Council is asked to consider the Security of Supply Annual Assessment 2020

1.1. The Security and Reliability Council's (SRC) functions include offering advice to the Electricity Authority on the security of the power system. One aspect of security is adequacy of generation investment to provide energy and capacity.

1.2. The system operator's annual Security of Supply Assessment (SOSA) is the primary source of information on adequacy of generation investment to provide energy and capacity over a time horizon of years.

1.3. The SRC is asked to consider the SOSA 2020 (attached as Appendix A), which covers energy and capacity adequacy to 2029. The secretariat notes that SRC members should not read the entire SOSA and offers the following guidance:

a) section one (the Executive Summary) is essential reading

b) section four is very relevant to the SRC, as it shows a broader range of results (with sensitivities) than the Executive Summary

c) sections two and three may be useful for readers unfamiliar with SOSA reports

d) section five and the appendices are detailed-oriented and should only be used by SRC members seeking to understand the mechanics of the methodology.

1.4. The SOSA was published in April 2020, following consultation. Submissions were received and the system operator made some revisions to the demand forecast and clarified some issues in the text before finalising the SOSA.

1.5. The system operator will attend the SRC meeting to answer any questions about the SOSA.

The SOSA framework

1.6. The security standards set by the Authority are:

e) a winter energy margin for New Zealand (NZ-WEM) of 14-16% greater than forecast energy consumption

f) a winter energy margin for the South Island (SI-WEM) of 25.5-30% greater than forecast energy consumption

g) a winter capacity margin for the North Island (WCM) of 630-780 MW greater than forecast peak demand (in MW). Note that this margin includes an allowance for instantaneous reserve (IR).

1.7. The margins set reflect that if under-supply occurs, there is an increase in costs to the country through loss of production and loss of load events. When over-supply occurs, there is a cost to consumers through cost recovery for the surplus generation. While the risks are asymmetric, the margins represent an efficient level of generation supply that minimises overall cost to the country.

1.8. The results against the margins help inform stakeholders whether an efficient level of energy or capacity generation supply exists now and in future scenarios. Results outside the efficient margins (especially results exceeding the margins) are not necessarily problematic. They are a single measure and need to be examined in a broader context before conclusions can be reliably drawn.

1.9. There are no legislative consequences for generators not meeting the efficient margins; the margins are intended to be informative. By contrast, measures like the customer compensation scheme and scarcity pricing are explicitly designed to provide incentives that augment spot price signals to better promote reliability.

1.10. The system operator is obliged to annually publish an assessment of security of supply against the NZ-WEM, SI-WEM and WCM margins.

1.11. The Authority provides certain assumptions that the system operator must use when preparing the annual assessment. These assumptions are published in the Security Standards Assumptions Document (SSAD).[1] The purpose of the SSAD is to help ensure that results against the margins are calculated in a way that is consistent with the derivation of the margins. The system operator can use alternative assumptions if it provides reasons for doing so and still notes the results of using the Authority's assumptions.

1.12. Demand forecasts were updated this year by Transpower to be consistent with its "Whakamana I Te Mauri Hiko" framework,[2] which considers the impact of more renewable generation and electrification.

Annual updates will be provided

1.13. The SRC will be updated on the Security of Supply Annual Assessment 2021 in a year's time.

1.14. The scenarios do not include medium to long term impacts arising from COVID-19. Further work is planned with the intention to publish refined COVID-19 sensitivities later this year. Once Transpower have published these the secretariat will consider whether it warrants bringing to the SRC's attention.

2. The findings of the SOSA 2020

Results for the four core scenarios

2.1. Rather than having a single base case, the assessment uses four core scenarios, an increase on the three scenarios assessed in 2019. The four scenarios are labelled:

1 https://www.ea.govt.nz/operations/wholesale/security-of-supply/security-of-supply-policy-framework/security-standards-assumptions/

2 https://www.transpower.co.nz/resources/whakamana-i-te-mauri-hiko-empowering-our-energy-future

a) low demand

b) medium demand

c) high demand (new scenario)

d) thermal constraints.

2.2. Existing thermal generation remains in place in the low, medium and high demand scenarios. The 'thermal constraints' scenario, driven by uncertainty about the future of thermal generation in NZ, involves a 500 MW reduction in thermal generation.

2.3. The 'low demand' scenario is characterised as "a world where New Zealand's response to climate change is delayed with limited electrification of transport and industry".

2.4. The new 'high demand' scenario "assumes a greater uptake of the technologies and trends observed in the Medium Demand scenario and assumes the underlying wholesale market demand for electricity grows strongly".

2.5. The Tiwai smelter remains in operation in all four core scenarios (though a sensitivity scenario in Appendix 2 models early Tiwai closure).

2.6. The scenarios do not include medium to long term impacts arising from COVID-19.

2.7. As in 2019, generation is divided into the following categories:

a) existing and committed

b) consented

c) not consented, but consent could be sought soon.

2.8. Section 4.1 of the SOSA forecasts that new generation investment will be needed as early as 2025-2026 (under all four scenarios) to meet peak winter demand. The capacity security standard will need 13-160 MW by 2026 with an extra 290-440 MW by 2029, and the national energy security standard will need 760-1280 GWh by 2029.

2.9. Appendix 1 provides forecasts of South Island energy margins, but these can be ignored as the national energy standard always binds before the South Island energy standard.

2.10. Under all four scenarios, there is enough consented generation to meet all three security standards to 2029. However, Transpower conclude generation projects beyond those it's presently aware of will be required as not all projects are likely to proceed.

Sensitivity analysis

2.11. Transpower have a web-application to view results and sensitivities. It is available at https://www.transpower.co.nz/system-operator/security-supply/annual-assessment-results.

2.12. There are some sensitivities in which new generation is needed earlier.

2.13. In each of the following sensitivities, new generation is needed to meet the national energy standard by 2024:

a) thermal decommissioning and medium or high demand

b) thermal decommissioning and thermal constraints.

Differences between the SOSA 2020 and last year's SOSA

2.14. This year's assessment projects a slightly higher level of security of supply than last year's:

a) the four SOSA 2020 scenarios forecast that new generation will be needed between 2025 and 2029 in order to meet the security standards

b) the three SOSA 2019 scenarios forecast that new generation would be needed between 2024 and 2026.

2.15. The SOSA methodology was essentially the same in 2019 as it was in 2020. Some input assumptions have changed, and an extra scenario was added.

2.16. The system operator notes one substantive change in the SOSA 2020. Winter peak demand forecast is now directly derived from each scenario's underlying demand forecast, which includes forecast changes to daily half hourly demand and all embedded generation (rather than selected 'large' embedded generators). The new method shows a winter peak demand increase compared to last year.

2.17. The key uncertainties remain the same – how quickly will demand grow and when will existing thermal generation retire?

3. Questions for the SRC to consider

3.1. The SRC may wish to consider the following questions.

Q1. Is the SRC comfortable with the SOSA 2020 results?

Q2. What further information, if any, does the SRC wish to have provided to it by the secretariat?

Q3. What advice, if any, does the SRC wish to provide to the Authority?

4. Appendices

4.1. Appendix A: *Security of Supply Annual Assessment 2020* (system operator)

Security of Supply Annual Assessment 2020

Transpower New Zealand Limited

April 2020

Keeping the energy flowing

TRANSPOWER

Version[1]	Date	Change
1.0	9/03/2020	Draft for industry review
2.0	30/04/2020	Final report

	Position	Date
Prepared by:	Caitlin Tromop van Dalen Market Analyst Steve Torrens Senior Market Analyst	April 2020

IMPORTANT

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[1] For previous assessments undertaken by the system operator refer to *https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment*

For similar assessments by the Electricity Commission prior to 2011, refer to http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/security-of-supply/asa/

Contents

1 Executive Summary

This document is Transpower's annual medium-term security of supply assessment. It provides a ten-year view (2020 to 2029) of the balance between supply and demand in the New Zealand electricity system. It considers four key supply and demand scenarios, covering energy and capacity.

The assessment presents three margins that, together, cover the key security of supply risks for the New Zealand electricity system; the New Zealand and South Island Winter Energy Margins (WEMs) and North Island Winter Capacity Margins (WCMs). The energy margins assess whether it is likely that there will be an adequate level of generation and HVDC transmission capacity to meet expected electricity demand across the winter months. The capacity margin assesses whether it is likely there will be adequate generation and HVDC transmission capacity to meet peak winter North Island demand.

In this year's annual assessment, the scenarios have remained largely consistent with those used in 2019, with similar themes retained. Demand forecasts have been updated so that they are consistent with Transpower's "Whakamana i Te Mauri Hiko" work, which considers the impact of more renewable generation and electrification.

The scenarios cover a range of plausible futures. Three of the four scenarios explore different demand growth rates. The Low Demand scenario is business as usual, with modest energy growth in New Zealand. The Medium Demand scenario is where there is an accelerated electrification of transport and industrial process heat which prompts higher rates of growth in the 2020s. The High Demand scenario considers an economy-wide mobilisation to decarbonise New Zealand's energy sector. It assumes a more aggressive uptake of the technologies and trends seen in the Medium Demand scenario. These energy demand forecasts for the three demand scenarios are shown in Figure 1.

We also include a fourth scenario, "Thermal constraints", to reflect uncertainty around the future generation mix. This uses the Medium Demand growth rates but assumes a limit on the addition of gas generation, by removing 500 MW from future supply.

All scenarios assume the New Zealand Aluminium Smelter (NZAS) at Tiwai Point remains viable until 2030. Given current levels of uncertainty our scenarios do not include the medium to long term impacts arising from Covid-19. We do, however, include a sensitivity where the potential impact of Covid-19 is explored. We plan to do further work in this area, with the intent of publishing additional refined Covid-19 sensitivities, in the second half of this year.

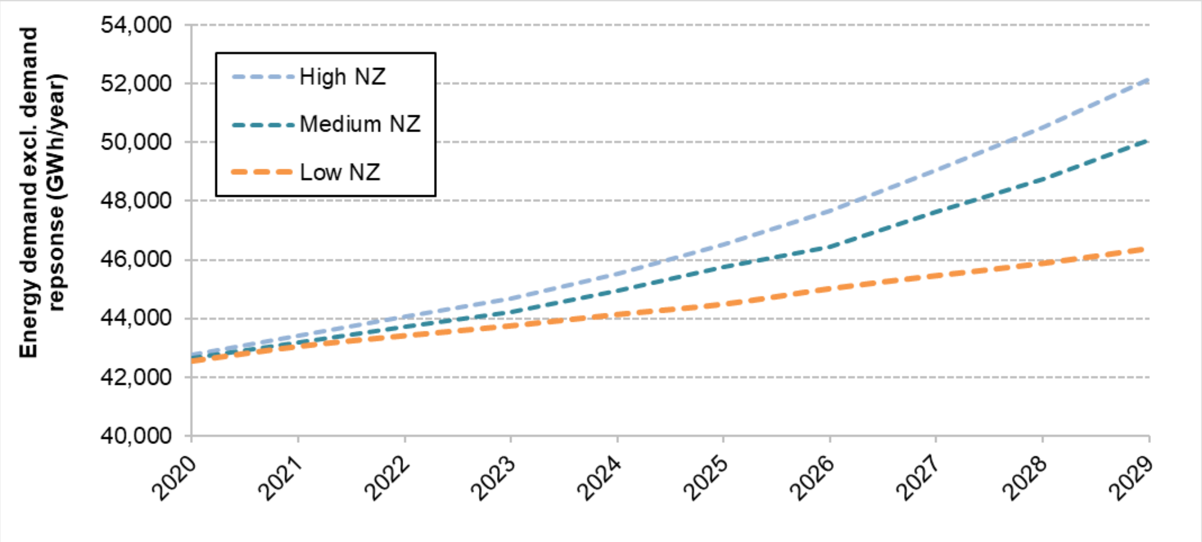

Figure 1: Energy demand forecasts for the three demand scenarios

Demand for electricity assumed in the assessment is based on Transpower's demand forecasts. For supply—that is existing and potential new generation—assumptions are supplied in confidence by generators and presented in aggregate in Figure 2. As with last year, we also model the potential impact of new technologies, including distributed solar generation and batteries. There are a significant amount of generation projects that are now being actively progressed and expected to be commissioned within the next two years, subject to some uncertainty due to Covid-19. These projects will contribute to North Island Winter Capacity Margins by 126 MW and New Zealand Winter Energy Margins by 801 GWh[2].

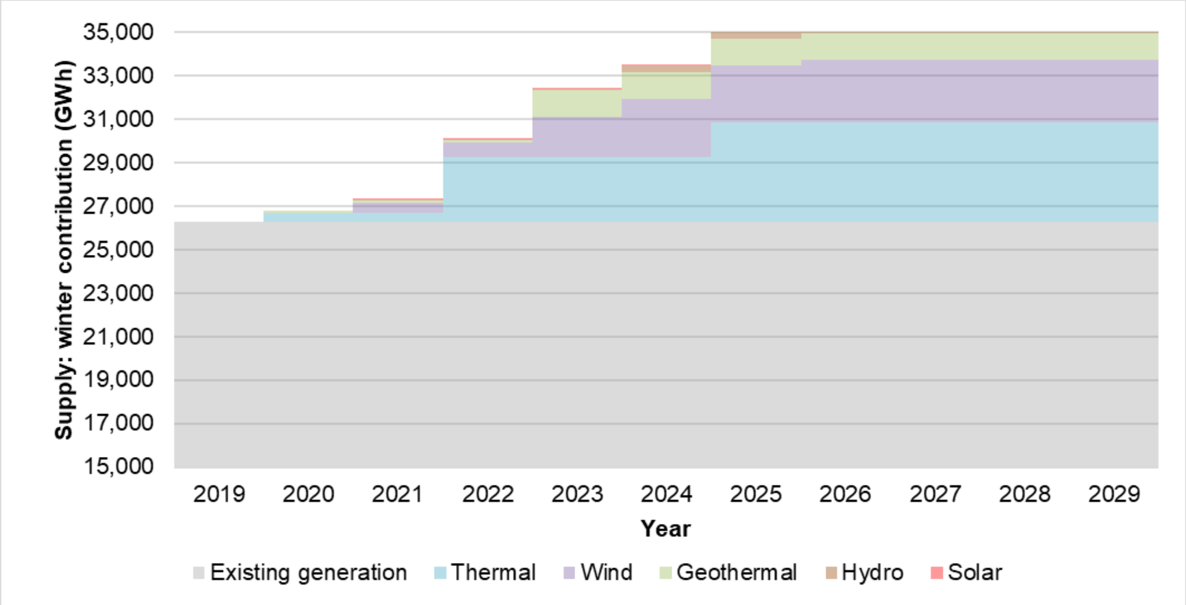

Figure 2: Modelled supply additions, by year of earliest availability

In all four scenarios, investment in new generation will be required by 2025 - 2026 in order to maintain North Island Winter Capacity Margins at an efficient level of reliability (that is, where the expected cost of supply shortages is equal to the expected cost of new generation).

New Zealand Winter Energy Margins are slightly less critical. New generation will be required to meet efficient levels by 2026 - 2027 for the Medium Demand and High Demand scenarios. No new generation is required within the assessment period for the Low Demand scenario.

New generation is required earlier to maintain North Island Winter Capacity Margins in part due to the type of generation projects that are currently being actively progressed. Over half of this capacity is wind generation, which contributes a relatively smaller amount to North Island Winter Capacity Margins than to the Winter Energy Margins.

For all scenarios, maintaining security of supply standards will require an ongoing pipeline of new generation, especially from the mid-2020s. Under the four main scenarios there are enough known new generation options that, if built, would ensure efficient levels of reliability in the coming decade. In the Medium Demand scenario, New Zealand will need to add at least 290 MW of new winter capacity and 760 GWh of new winter generation by 2029. For the more conservative Low Demand scenario New Zealand will still need to add at least 160 MW of new winter capacity by 2029.

These results are illustrated in the diagrams below. For each scenario, the lower, light bands are existing or committed generation. The upper, dark bands are known new generation options that could be built.

[2] This excludes Junction Road, which was commissioned in March 2020. In comparison, in last year's assessment, committed projects were expected to contribute to North Island Winter Capacity Margins by 107 MW and New Zealand Winter Energy Margins by 415 GWh.

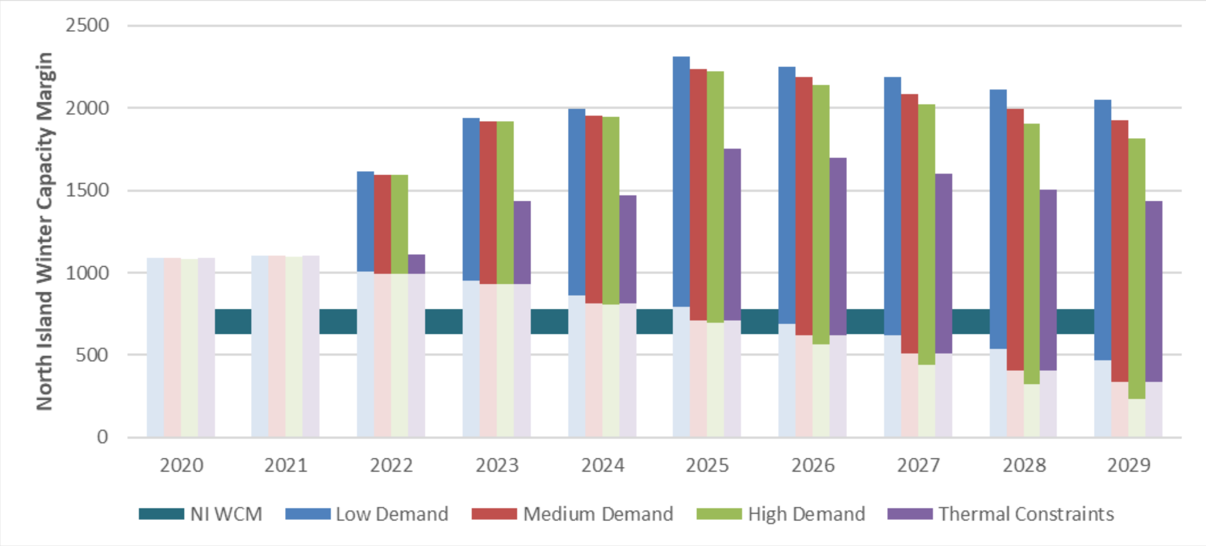

Figure 3: North Island Capacity Margin for all scenarios

In last year's assessment, for the Medium Demand scenario, we forecast the need for new generation to maintain the North Island Winter Capacity Margin by 2025 (one year earlier). This year's margin has improved in line with an increase in committed, actively progressed generation projects. Greater quantities of generation were offset by an increase in forecast winter peak demand. Winter peak demand has increased, in part, due to a change in forecasting methodology.

In contrast, New Zealand Winter Energy Margins have increased. In 2019, for the medium demand scenario, we forecast that new generation would be required by 2023 (and we now forecast 2026). This change is due to an increase in committed, actively progressed generation projects and, to a lesser extent, decrease in forecast winter energy demand.

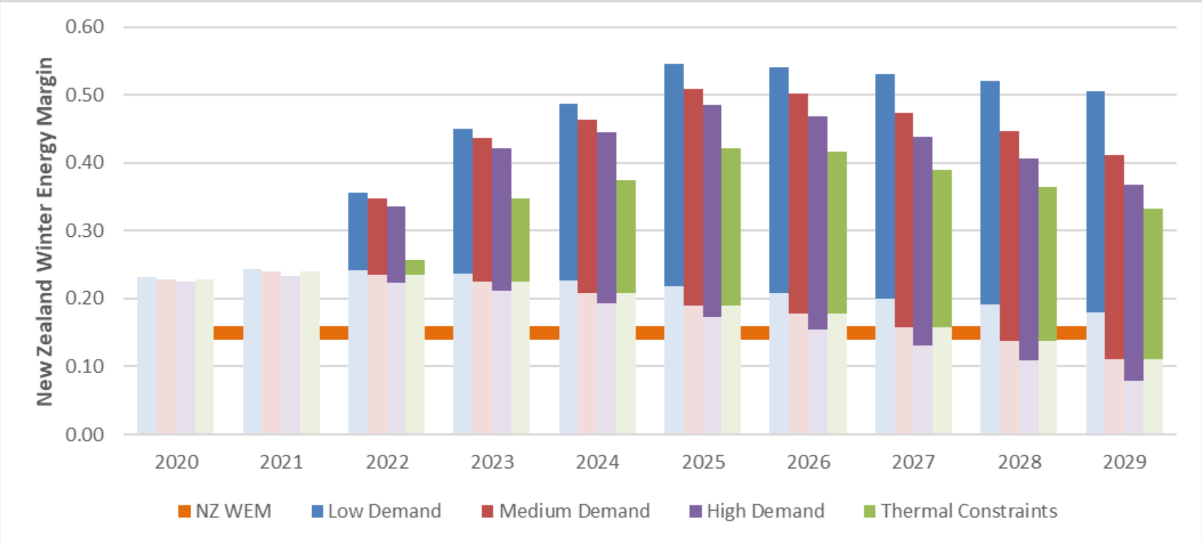

Figure 4: New Zealand Winter Energy Margin for all scenarios

We also consider several sensitivities in our analysis. Supply margins are shown to be particularly sensitive to potential scenarios of thermal plant decommissioning in 2023 and ramping down of the NZAS smelter at Tiwai Point over 2023 to 2027.

The annual assessment results are based on a simplified model of the New Zealand electricity system. The assessment makes several assumptions that should be considered when drawing conclusions:

- Forecast new generation timelines do not account for the consenting and construction times for additional transmission infrastructure, nor do they account for intra-island locational issues (such as regional voltage issues). This may delay commissioning dates in situations where major transmission investment is required. One of the sensitivities we have assessed considers the impact of delaying commissioning of all potential new generation by one year to reflect potential connection timing constraints. Even with this delay there is still enough new generation options to continue to meet the security of supply standards.

- All scenarios highlight the reliance on consented (but on-hold) generation to meet security of supply standards. If these projects are not committed before their consents lapse, then new consents or other sources of generation will be required. This may delay commissioning dates in some instances.
- The Low, Medium and High Demand scenarios assume that future thermal generation projects will be able to source enough fuel, supplied at the right level of flexibility, to contribute their full capacity to security of supply margins. If there are future shortages of fuel, then this may delay or prevent future thermal generation projects from being built. The Thermal Constraints scenario can be used to explore the impact of such delays.

2 Background

2.1 Assessment Context

This document is Transpower's annual medium-term security of supply assessment. Its purpose is to inform risk management and investment decisions by generators, other market participants, and investors.

It forms part of New Zealand's electricity security of supply framework. Transpower performs other security of supply-related functions described in its *Security of Supply Forecasting and Information Policy* and the *Emergency Management Policy*.[3] These include:

- Short-term monitoring and information provision, such as the weekly reporting of hydro levels relative to the electricity risk curves.
- Implementation of emergency measures where necessary.
- Detailed assessment of grid capability to meet demand over the next three years, available in Transpower's System Security Forecast.
- Detailed capacity assessment for the current year, available in Transpower's New Zealand Generation Balance assessment.

For more detail on the security of supply framework see *https://www.transpower.co.nz/system-operator/security-supply*.

2.2 Security of Supply Assessment

This assessment provides a medium-term view of the balance between supply and demand in the New Zealand electricity system. The security of supply assessment forecasts two winter margins, the Winter Energy Margin (WEM) and the Winter Capacity Margin (WCM).

- The energy margins, for New Zealand and the South Island, are the sum of the respective available winter energy supply, in gigawatt-hours (GWh), divided by the expected winter energy demand, in GWh. The margins are expressed as a percentage of total demand.
- The capacity margin is the sum of North Island generation capacity less the expected peak demand plus surplus South Island capacity able to be sent via the HVDC link to the North Island.[4] The margin is expressed as a megawatt (MW) value.

Winter is defined as the period from April to October for the WCM, and April to September for the WEMs.

The energy margins assess whether it is likely there will be an adequate level of generation and, in the case of the South Island, HVDC south transmission capacity, to meet expected electricity demand during the winter. The capacity margin assesses whether it is likely there will be adequate generation and HVDC north transmission capacity to meet peak North Island demand.

Security of supply standards are defined by the Electricity Authority as part of its responsibility to ensure that the regulatory environment promotes an efficient level of reliability. The standards represent an efficient level of reliability—that is the expected cost of shortage is equal to the expected cost of new generation.

[3] *https://www.transpower.co.nz/system-operator/security-supply/security-supply-forecasting-and-information-policy*

[4] Noting we do not make allowances for spinning reserve—that is, the peak demand is not increased by the amount of reserves required. This means the subsequent margin represents excess supply *prior* to the provisioning of reserves. Thus, the actual margin observed would be available, but not dispatched generation, and reserves required.

The current security of supply standards[5] specified in the Code[6] are:

- a WEM of 14-16% for New Zealand,
- a WEM of 25.5-30% for the South Island
- a WCM of 630-780 MW for the North Island.

Falling below the standards does not equate to electricity shortage. It simply implies that investment in new generation would result in an efficient increase to reliability. It can also be interpreted as representing the *likelihood* of electricity shortage—the higher the actual margin observed the less likely electricity shortage will be.

A more detailed description of the security of supply assessment methodology may be found in Appendix 3: Methodology.

[5] The Electricity Authority reviews the security of supply standards on a regular basis to ensure they account for the risks to supply, the mix of generation and demand side technologies employed by participants, uncertainty in primary fuel availability (especially hydro inflow uncertainty), and costs.

[6] Clause 7.3(2), Part 7 of the Electricity Industry Participation Code 2010.

3 Analysis

We use four scenarios[7] to represent quite different, but plausible, futures.

The Low Demand, Medium Demand and High Demand scenarios capture a range of possible electricity demand growth rates. Demand growth rates vary according to the level of electrification and uptake of new technologies that may occur to meet New Zealand's climate change goals. These demand scenarios align with Transpower's Whakamana I Te Mauri Hiko work[8].

The fourth scenario, Thermal Constraints, uses medium demand growth assumptions but limits the growth of new thermal generation.

Our supply assumption also includes forecast growth in distributed solar generation and battery storage. Growth rates in these technologies are internally consistent with our demand scenarios.

Existing supply and new generation options (excluding small scale distributed technologies) used in these scenarios are those reported to us by generators in confidence and the results are presented in a way that seeks to preserve that confidence.

3.1 Scenarios

The four scenarios are:

- **Low Demand**: this scenario represents a world where New Zealand's response to climate change is delayed with limited electrification of transport and industry. As a result, electricity demand growth is business as usual, as observed from recent years. This scenario assumes an underlying wholesale market demand for electricity growth averages 1.0 per cent across the decade.
- **Medium Demand**: this scenario involves a coordinated, but moderate response to climate change—increasing electricity growth is observed as regulation and market incentives lead to the accelerated electrification of transport and process heat. This effect starts slowly but grows over time and this scenario assumes underlying wholesale market demand for electricity grows at an average of 1.8 per cent per year.
- **High Demand:** This scenario sees an economy-wide mobilisation to decarbonise New Zealand's energy sector. It assumes a greater uptake of the technologies and trends observed in the Medium Demand scenario and assumes the underlying wholesale market demand for electricity grows strongly at an average of 2.2 per cent per year.
- **Thermal Constraints**: this scenario represents a future where gas-fired thermal generation growth is limited. It uses the same demand outlook as the medium demand scenario above but assumes 500 MW of new gas-fired thermal generation is unavailable. This could occur if less new thermal generation is built, or, equivalently, existing thermal generation is reduced by 500 MW. This scenario could cover a variety of futures, including where sufficiently flexible gas supply is either unavailable or uneconomic, such that future thermal generation build is restricted.

In the absence of firm announcements to the contrary, we assume the NZAS at Tiwai Point remains under all scenarios for the forecast period. The impact of the smelter closure is explored as a sensitivity.

For further information on the assumptions used in this assessment see section 5 for high level information and appendices 3 - 6 for detailed information.

[7] In this document, we use the term scenario to denote a standalone, plausible future. We use sensitivities to denote exploration of the impact of various factors on each of these scenarios.

[8] Whakamana i Te Mauri Hiko - Empowering our Energy Future available at *https://www.transpower.co.nz/resources/whakamana-i-te-mauri-hiko-empowering-our-energy-future*

3.2 SENSITIVITIES

Several sensitivities to changes in supply and demand were assessed against the scenarios, including:

- **NZAS closure:** NZAS ramps down production from 2023**.**
- **Thermal decommissioning:** One of the two Combined Cycle Gas Turbines shuts down in 2023.
- **Delayed build times:** Generation takes longer than expected to be built.
- **Reduced generation availability:** a 5 per cent reduction in existing and future non-thermal generation output to account for lower than expected generation output. This sensitivity covers a number of potential situations including, lower than expected wind capacity factors, geothermal steam field pressure or solar radiation.
- **Future renewable generation increase:** a 5 per cent increase in future, uncommitted, renewable generation. This sensitivity covers a situation where the amount of future renewable generation is greater than expected.
- **Change in peak transmission pricing**: Peak demand increases for a short period of time as the industry adjusts to a change in peak transmission pricing.
- **Delayed demand growth due to Covid-19**: Growth in energy demand is stalled from March 2020, and then, after 18 months, the growth rate returns to normal pre-Covid-19 levels This is an early, 'first-cut' indication of the medium to long term impacts of Covid-19.

The results of these sensitivities are shown in Appendix 2: Sensitivities.

3.3 ASSESSMENT CHANGES

In previous years, winter peak demand forecast was derived by:

- Finding, for the base year of the analysis, the average quantity (in MW) supplied by grid-connected and large embedded generation for the highest 200 half hours of winter daytime demand.
- This quantity of generation was then increased in line with the growth rates for annual peak demand (the highest demand in any half-hour period over a year) to derive a peak winter demand forecast.

This year's winter peak demand forecast is derived directly from each scenario's underlying demand forecast, which includes forecast changes to daily half hourly demand. The benefits of this more direct approach include:

- The winter peak demand forecast (used for the WCM) is now internally consistent with the winter energy demand forecast (used for the WEM).
- Contributions to peak demand from distributed technologies, such as batteries, can be assessed. Winter peak demand now includes, in effect, demand served by grid-connected generation, all embedded generation and batteries.
- The forecast is no longer coupled to a 'base year', where peak demand may have been relatively low or high.

Compared to last year's forecast, winter peak demand has increased. This increase is in part due to the new method used to derive winter peak demand and as the forecast now includes all embedded generation (rather than selected 'large' embedded generators).

4 RESULTS

4.1 DISCUSSION OF RESULTS

This assessment indicates that over all scenarios there are enough known new generation options to ensure efficient levels of reliability in the coming decade. For the High Demand or Thermal Constraints scenarios, further new generation projects may need to be identified so that a reasonable buffer of generation projects is maintained through the 2020s.

If no new generation is built, it is expected that all margins will fall below security of supply standards at approximately midway through the next decade. Should this happen the New Zealand electricity system could face increased risk of shortfalls in trying to meet demand in winter. New generation investment is required as early as 2025-2026 for all assessed scenarios.

In context, to maintain the New Zealand Winter Capacity Margin at the security standard, under the Medium Demand scenario, we need to commission between 13–160 MW of new winter generation capacity by 2026, with an additional 290–440 MW required by 2029. This is capacity that can reliably meet winter peak demand. The actual amount of *installed* capacity required will vary according to the type of new generation being built. Intermittent generation (wind or solar) contributes a relatively small proportion of its full installed capacity to reliably meet winter peak demand, as compared to firm generation (thermal or geothermal). To maintain the New Zealand Winter Energy Margin at the security standard, for the same scenario, 760–1280 GWh of new winter generation will be required by 2029.

New Zealand has significant generation potential from many sources, with many high quality geothermal and wind sites, yet be developed. Subject to a stable investment environment, it should be possible to meet the standards over the next 10 years, providing that participants are continuing to advance projects to consent and build on these resources. Generation projects beyond those that we are presently aware of will be required as not all projects in our assessment are likely to proceed.

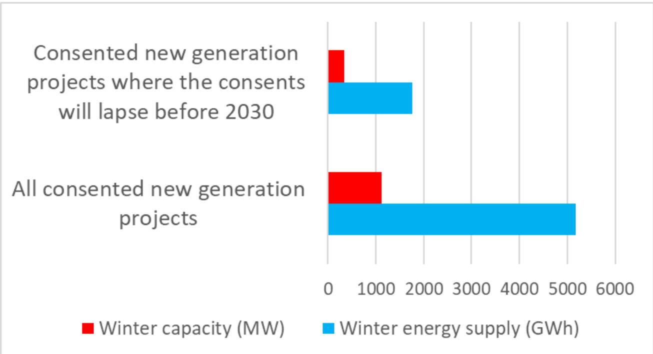

Figure 5: Consented generation projects that may expire by 2029

There remains a healthy pipeline of new generation options that are currently consented and awaiting market conditions to change before they are progressed. For a significant proportion of these projects, however, the consents will lapse ahead of 2029 (see Figure 5, left). While we expect[9] that these projects will be reconsented, this is an area that we will continue to monitor.

This assessment makes simplified assumptions around the timing of generation investment. Investment decisions are closely linked to market conditions. As market conditions are often volatile and difficult to forecast there is a large amount of uncertainty associated with when generation investment will occur. The results of this assessment present potential generation investment with generic timings, rather than attempting to guess when specific generation plant may be built. The timings for specific projects may be delayed, due to a variety of factors, and this may mean that margins may be lower than those presented in this assessment.

Key project risks include, in particular:

- Timings for new generation do not account for transmission consent and build times, nor do they account for intra-island locational issues (such as regional voltage issues) . This may cause delays for some projects as these issues are resolved[10].

[9] The assessment calculates security margins based on known potential new generation projects and their status as of the time of the report. We do attempt to predict which consented projects will be reconsented on expiry of their consent. For each potential new generation project, we simple assume its status remains unchanged throughout the period of assessment.

[10] Although outside the scope of assessing the WCM, should thermal generation be withdrawn from the Waikato region ahead of new generation or transmission in the northern Waikato or further north, the ability to meet

- The Low, Medium and High Demand scenarios assume that future thermal generation projects will be able to source enough fuel, supplied at the right level of flexibility, to contribute their full capacity to security of supply margins. If there are future shortages of fuel, whether this driven by resource availability or price, then this may delay or prevent some future thermal generation projects from being built.

4.2 Interpretation of Results

The charts in this section show the margins for the three key scenarios assessed. Each chart presents three key pieces of information:

- *The security standard represented by a horizontal blue or orange line on the charts*. This is a reference to compare the margins against. Security standards are calculated by the Electricity Authority as the upper and lower margins that represent an efficient level of reliability.
- *The margins calculated with the electricity supply from existing and committed generation.* This is represented by the grey bars on the charts. As time passes, and demand grows, the margin based on this generation decreases.
- *The margins with new generation added.* That is, the margins if all known new generation options are built (assuming some practical limitations on lead times). This is represented by the series of red coloured bars on the charts.

We have drawn conclusions from the results by firstly analysing what the future looks like with no new generation. Following this, we made an assessment on the ability of known new generation options to meet the security standard in the future. If there is a significant volume of new generation options available that, when added to existing generation, results in a margin that exceeds the security standard, then it is likely the electricity system will be able to maintain the margin at or near the security standard.

Conversely, if the sum of known generation options, on top of existing generation, results in a margin that is below the standard then industry participants will need to investigate and develop new generation options beyond that already known, or the margin may fall below the standard, and the New Zealand electricity system may experience inefficiently high levels of shortage risk. This situation does not occur in any of the current scenarios.

For perspective, in the New Zealand WEM analysis, to increase the margin by 5 per cent would require approximately 1,000 GWh of generation over the period April to September inclusive.[11]

The South Island WEM analysis results are not shown in this section as they are not materially different from the conclusions of the New Zealand WEM analysis. For full results, including South Island WEMs, and a complete set of results from the sensitivity analysis please see Appendix 1: South Island Winter Energy Margin Results and Appendix 2: Sensitivities respectively.

demand in this region could become constrained. For more information please see: https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation

[11] 1,000 GWh of winter generation is equivalent to a 230-240 MW of geothermal generator (95-98 per cent capacity factor) or a 560-570 MW wind farm (40 per cent capacity factor).

4.3 ENERGY MARGIN RESULTS

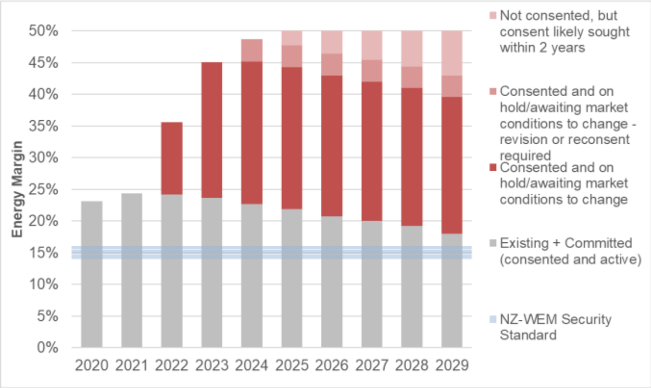

Figure 6: NZ WEM – Low Demand

- In the Low Demand scenario, it is expected that no new generation is required to meet the NZ WEM standard over the period of assessment.

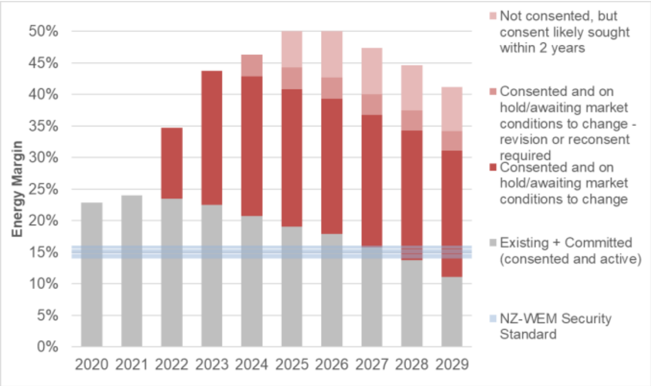

Figure 7: NZ WEM – Medium Demand

- In the Medium Demand scenario, it is expected that, without additional generation, we will fall below the NZ WEM standard in 2028.
- Some consented generation will need to be commissioned and built within eight years to continue to meet the NZ WEM standard.
- By 2029 at a minimum[12] ~760 GWh of new winter generation is required to maintain the standard.

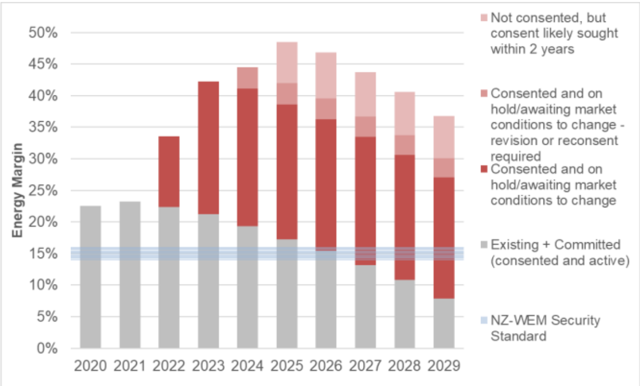

Figure 8: NZ WEM – High Demand

- In the High Demand scenario, it is expected that, without additional generation, we will fall below the NZ WEM standard in 2027.
- Some consented generation will need to be commissioned and built within seven years to continue to meet the NZ WEM standard.
- By 2029 at a minimum ~1,650 GWh of new winter generation is required to maintain the standard. This is 21 per cent of the total pipeline of future generation.

[12] Where 'at a minimum' in this context is the amount of generation required to return margins to the minimum level for each security standard.

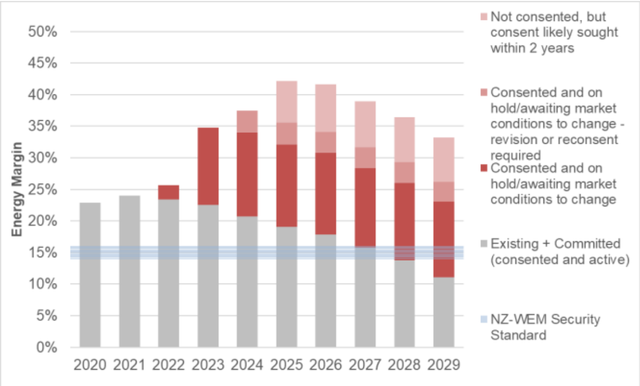

Figure 9: NZ WEM – Thermal Constraints

- In the Thermal Constraints scenario, it is expected that, without additional generation, we will fall below the NZ WEM standard in 2028.
- New generation supply required is the same as that in the Medium Demand scenario, but this additional 760 GWh is now 13 per cent of the pipeline of generation (up from 10 per cent with including an additional 500 MW of thermal generation).

4.4 CAPACITY MARGIN RESULTS

When calculating the North Island Winter Capacity Margins, no allowance has been made for generation used to provide instantaneous reserves. The peak margin is simply the difference between supply and demand, and hence a portion of this margin must be used to provide instantaneous reserves. For example, if the winter capacity margin is 1,000 MW, this value includes approximately 300-600 MW that would be needed for instantaneous reserves.

While not explicitly considered in this assessment, we acknowledge that North Island Winter Capacity Margins may also be improved by increasing HVDC transfer capacity, as an alternative to adding more generation capacity.

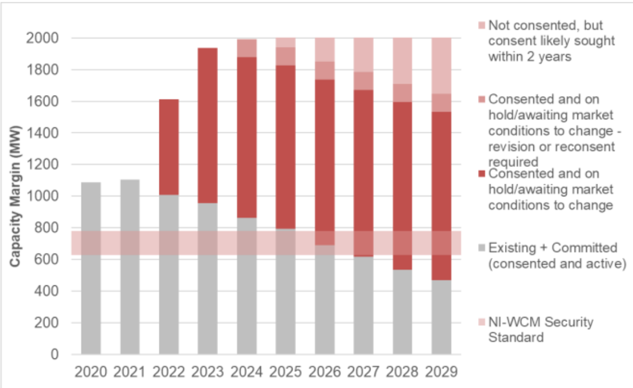

Figure 10: NI WCM – Low Demand

- In the Low Demand scenario, it is expected that, without additional generation, we will be below the NI WCM standard from 2027.
- Some consented generation will need to be commissioned and built within six years to continue to meet the NZ WEM standard.
- In 2029 at a minimum ~160 MW of peaking capacity will be required to meet the NI WCM standard.

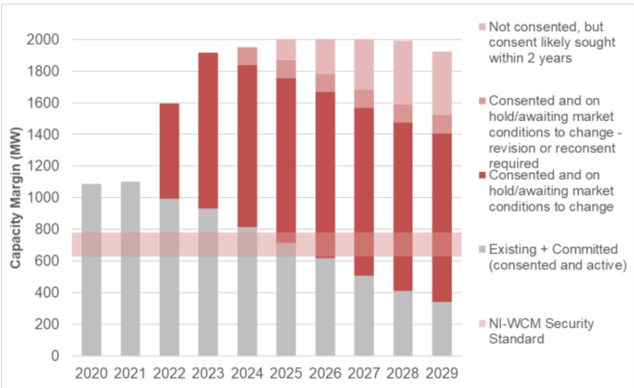

Figure 11: NI WCM – Medium Demand

- In the Medium Demand scenario, it is expected that, without additional generation, we will be below the NI WCM standard from 2026.
- Some consented generation will need to be commissioned and built within six years to continue to meet the NZ WEM standard.
- In 2029 at a minimum ~290 MW of peaking capacity will be required to meet the NI WCM standard.

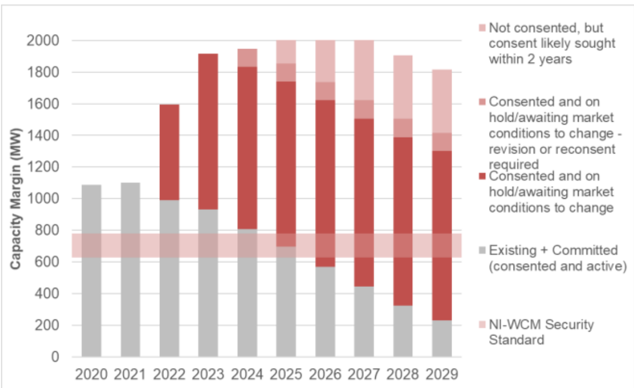

Figure 12: NI WCM – High Demand

- In the High Demand scenario, it is expected that, without additional generation, we will be below the NI WCM standard from 2026.
- Some consented generation will need to be commissioned and built within six years to continue to meet the NZ WEM standard.
- In 2029 at a minimum ~400 MW of peaking capacity will be required to meet the NI WCM standard. This is approximately 24 per cent of the total pipeline of new generation projects.

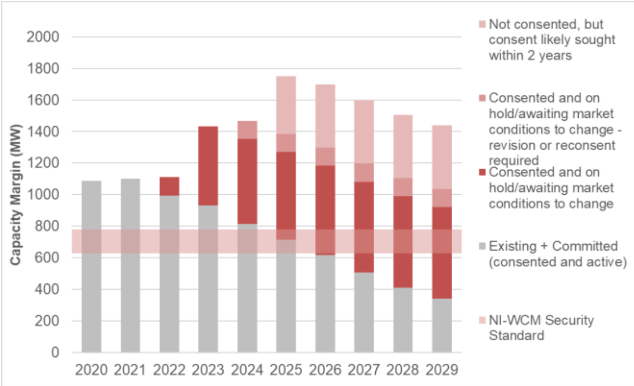

Figure 13: NI WCM - Thermal Constraints

- In the Thermal Constraints scenario, it is expected that, without additional generation, we will be below the NI WCM standard from 2026.
- New generation supply required is the same as that in the Medium Demand scenario, but this additional 290 MW is now 25 per cent of the total pipeline of generation (and 46 per cent of future projects with consent).

5 INPUT ASSUMPTIONS

A set of standardised assumptions are used to determine the margins[13]. The main input assumptions used in this assessment were the levels of:

- electricity generation (existing and proposed new projects)
- electricity demand (including demand response)
- inter-island transmission capability.

5.1 DEMAND FORECAST

Future electricity demand is a critical factor to consider when assessing security of supply. For this assessment we prepare both winter peak demand forecasts (for the WCM) and winter energy demand forecasts (for the WEMs) for each scenario[14]. For this year's assessment, forecasts are aligned with Transpower's "Whakamana i Te Mauri Hiko" work.

We use an ensemble approach when preparing our demand forecasts. A base ensemble demand forecast (the 'base forecast') is derived from a combination of:

- Traditional econometric forecast
- Long term linear regression
- Short term linear regression
- MBIE Energy Demand and Generation Scenarios.

Electricity market reconciliation data[15] (up to 2019 for the final report and, up to 2018 for the draft report) is a primary forecasting input. The base forecast is derived on a 'gross basis', it includes demand served from the grid and from embedded generation. The base forecast is calculated for each grid exit point (GXP) and on a half hourly basis.

Demand forecasts, used for each scenario, start with a base forecast. This forecast is then adjusted to account for any known step changes or future deviations from what has been historically observed. For example, the demand forecasts used for the Medium Demand and High Demand scenarios are adjusted to take account of varying levels of electrification of process heat and transport.

Winter energy demand is calculated by summing base forecast demand, over each GXP in both islands, and over each winter half hour period. Winter peak demand is calculated by averaging base forecast demand, over each island, and over the highest 200 half hours of winter daytime demand.

Transmission losses are calculated by determining GXP offtake quantities and applying a static loss factor. These losses are added to each winter peak and energy demand to provide the minimum about of generation required for that forecast.

The flow chart below, Figure 14, shows how both the underlying peak and energy forecasts are determined.

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[13] The assumptions and methodology are based on the Electricity Authority's Security Standards Assumptions Document (SSAD) http://www.ea.govt.nz/dmsdocument/14134 .

[14] Although the forecast for the Medium Demand and Thermal Constraints scenarios are the same.

[15] Which provides electricity purchase quantities (demand in MWh) and sales quantities (generation in MWh) by GXP, grid injection point (GIP) and half hour trading period.

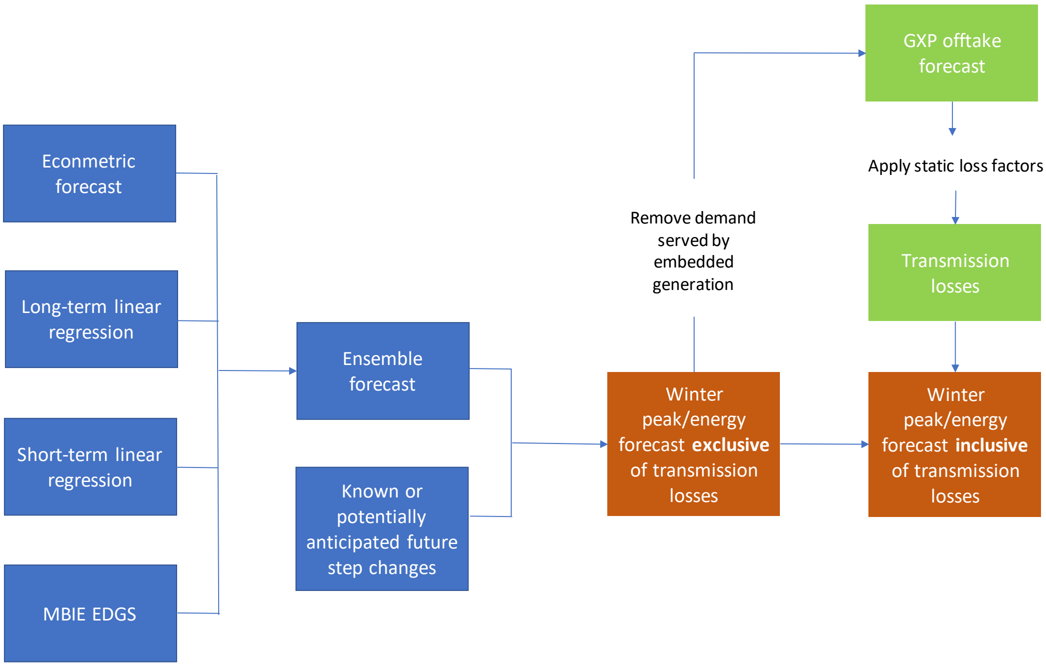

Figure 14: Schematic of how demand forecast is prepared

See Appendix 6: Detailed Demand Forecast Assumptions for more detailed assumptions about the electricity demand forecast used in this assessment.

5.2 GENERATION ASSUMPTIONS

Generation companies are surveyed confidentially about their existing and proposed new generation.

The expected winter energy supply in GWh used to determine winter energy margins is the sum of:

- controlled hydro generation based on an average hydrological year[16]
- thermal generation capacity de-rated to allow for any outages, multiplied by the number of winter hours
- other major sources of generation (uncontrolled hydro, geothermal, wind, co-generation, solar) based on reported capacity and utilisation, multiplied by the number of winter hours
- forecast distributed solar generation and battery discharge quantities.

The expected generation capacity in MW used to determine the winter capacity margin is the sum of:

- expected thermal and controlled hydro generation capacity, de-rated to allow for any outages
- expected winter peak contributions for all other generation (uncontrolled hydro, geothermal wind, co-generation, solar, batteries) based on historical winter peak contributions (in MW)
- forecast winter peak contributions from distributed solar generation and battery discharge (in MW).

All existing generation is expected to remain operationally available throughout the assessment period unless otherwise stated, with the exception of generation with a publicly notified retirement date.

We assume thermal fuel availability, or operational limitations, will not constrain thermal generation, except for the Whirinaki diesel generator. Whirinaki's energy contribution is limited to 30 GWh per winter period for the calculation of the WEMs due to fuel delivery logistics. Other thermal generation is reliant on coal or gas. We do not have sufficient evidence to suggest that availability of these fuels would significantly constrain output from existing or future thermal generation should there be a winter supply shortage.

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[16] This is the average of inflows into controlled hydro lakes in years 1931 to 2018.

Proposed new generation options have been aggregated to preserve confidentiality. New generation development options under consideration by investors may or may not proceed for a variety of reasons. New generation projects have been allocated to four categories:

- Consented and proceeding (i.e. committed).
- Consented and on hold/awaiting market conditions to change.
- Consented and on hold/awaiting market conditions to change—consent revision, or reconsenting will be required.
- Not consented.

The dates at which new generation becomes available is based on the type of generation, and its consent status. Table 1 shows the earliest potential commissioning dates for different types of generation and the consent status.

Table 1: Earliest new generation commissioning dates based on consent status and generation type

	Committed	Consented and on hold	Consented, on hold, requires consent revision	Not consented
Thermal	Estimated build date	2022	2023	2025
Geothermal	Estimated build date	2023	2024	2026
Wind	Estimated build date	2023	2024	2026
Hydro	Estimated build date	2024	2025	2027
Solar (large scale)	Estimated build date	2022	2023	2025

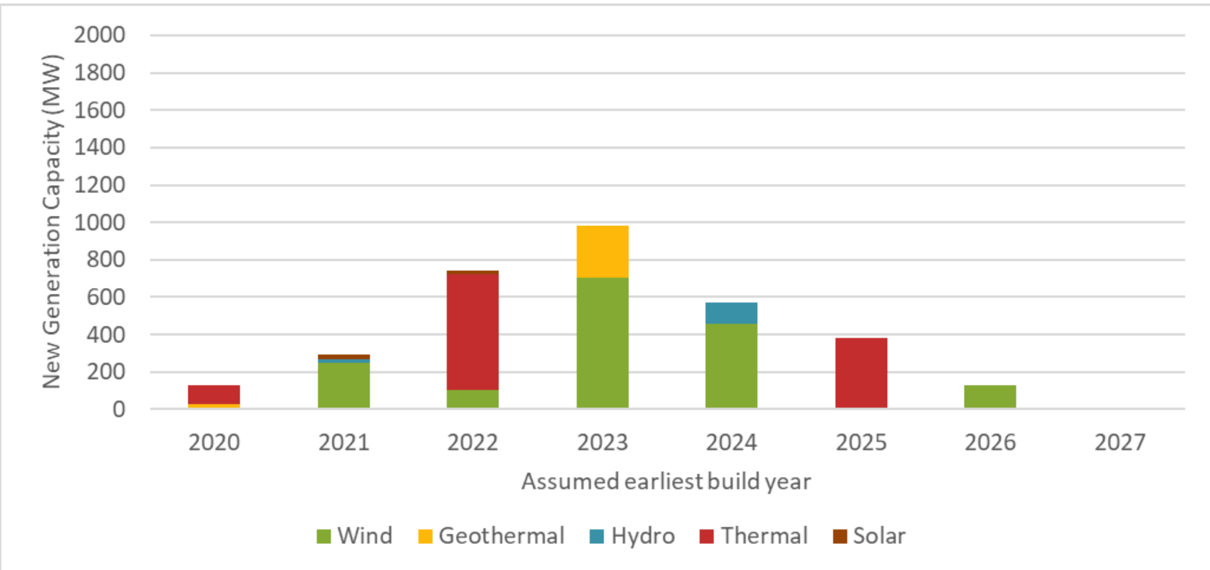

Figure 15: New generation timeline in Low, Medium and High Demand scenarios (distributed solar and batteries not shown)

It is assumed that generation could be built in the timeframes described, but it is expected that generation will be built when market conditions justify investment, as such the above information should be treated as *potential* generation available, and not representative of what *will* be built. It is also likely that some time frames will vary—for example, delays may occur for a variety of reasons (for example plant availability, logistics, transmission requirements); similarly, some projects may be expedited if market conditions justify it.

See Appendix 4: Detailed Supply Assumptions for further details about existing and new generation supply assumptions.

5.3 INTER-ISLAND TRANSMISSION ASSUMPTIONS

North Island energy supply can meet some of the South Island's energy demand in the assessment of the South Island WEMs. It is assumed the North Island will be able to supply the South Island with up to 2,102 GWh (480 MW average transfer) of energy during the winter period, depending on the surplus energy available in the North Island[17].

Similarly, South Island capacity can meet some North Island demand in the assessment of the North Island WCMs. The contribution of the South Island is a function of the surplus capacity available in the South Island and has been derived using simulation analysis.

See Appendix 5: Transmission for detailed assumptions about inter-island transmission.

[17] Energy surplus in the North Island is calculated by subtracting North Island demand from available North Island supply.

Appendix 1: South Island Winter Energy Margin Results

1.1 South Island Winter Energy Margins

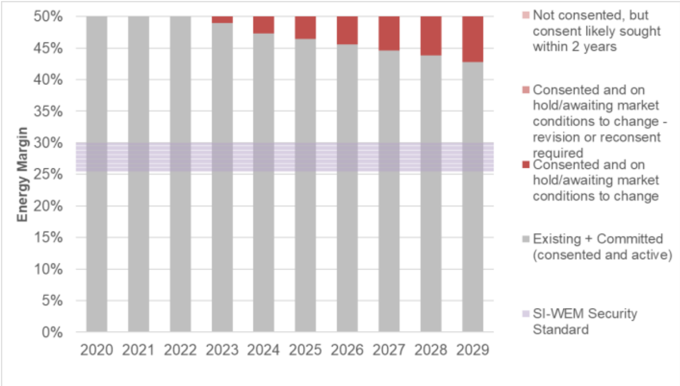

Figure 16: SI WEM – Low Demand

- In the Low Demand scenario, it is expected that no new generation is required to meet the SI WEM standard over the period of assessment.

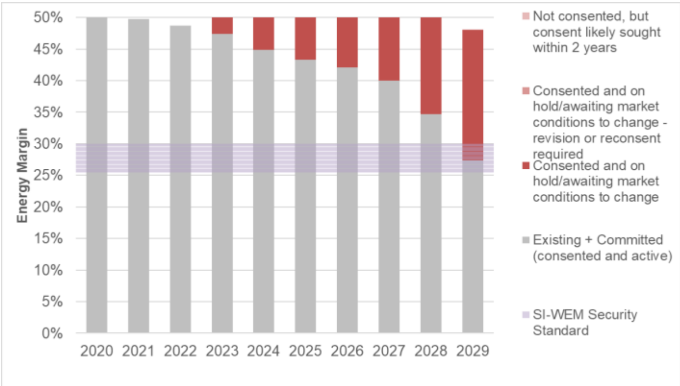

Figure 17: SI WEM – Medium Demand

- In the Medium Demand scenario, it is expected that no new generation is required to meet the SI WEM standard over the period of assessment.

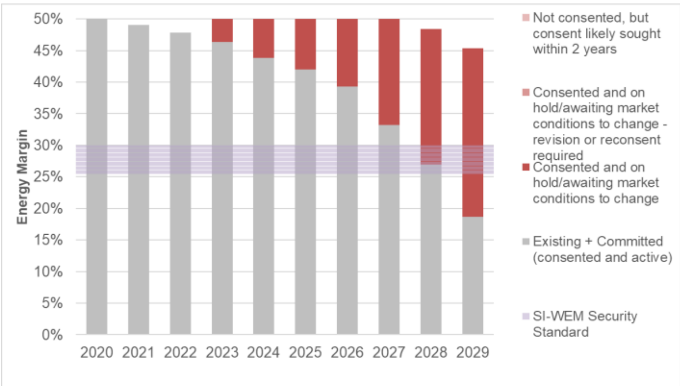

Figure 18: SI WEM – High Demand

- In the High Demand scenario, it is expected that, without additional generation, we will fall below the standard in 2029.
- Some consented generation will need to be commissioned and built within nine years to continue to meet the SI WEM standard.
- By 2029 approximately 650 GWh of new winter generation is required to maintain the standard.

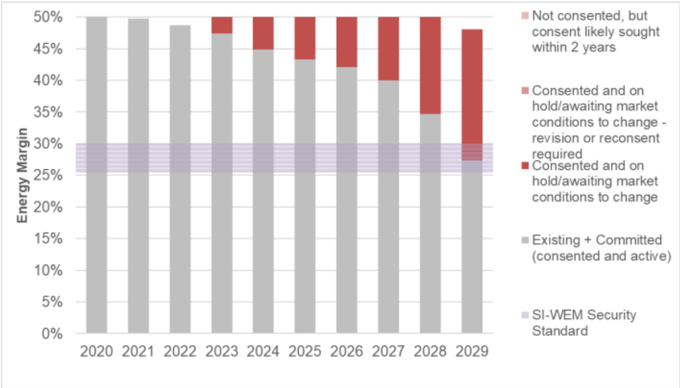

Figure 19: SI WEM – Thermal Constraints

- In the Thermal Constraints scenario, it is expected that no new generation is required to meet the SI WEM standard over the period of assessment.

Appendix 2: SENSITIVITIES

A number of sensitivities to changes in supply and demand were assessed against the scenarios.

Table 2 describes the change to assumptions for each of the following sensitivities:

- **NZAS closure:** NZAS ramps down production from 2023
- **Thermal decommissioning:** One of the two Combined Cycle Gas Turbines shuts down in 2023.
- **Delayed build times:** Generation takes longer than expected to be built.
- **Reduced generation availability:** a 5 per cent reduction in non-thermal generation output to account for lower than expected generation output. This sensitivity covers a lot of potential situations including, but not limited to, lower than expected wind capacity factors, geothermal steam field pressure or solar radiation.
- **Future renewable generation increase:** a 5 per cent increase in future, uncommitted, renewable generation. This sensitivity covers a situation where the amount of future renewable generation is greater than expected.
- **Change in peak transmission pricing**: Peak demand increases for a short period of time as the industry adjusts to a change in peak transmission pricing.
- **Delayed demand growth due to Covid-19**: Growth in energy demand is stalled from March 2020, and then, after 18 months, the growth rate returns to normal pre-Covid-19 levels. This is an early, 'first-cut' indication of the medium to long term impacts of Covid-19.

This year we have are prepared a web-application to view sensitivities. This is available on the Transpower website: *https://www.transpower.co.nz/system-operator/security-supply/annual-assessment-results*.

Table 2: Sensitivities

Sensitivity	Affects Energy	Affects Capacity	Rationale	Assumptions
NZAS closure	Yes	Yes	This sensitivity explores the situation where the NZAS at Tiwai point starts reducing its output from 2023 and closes at the end of 2027.	NZAS reduces load in stages beginning in 2023 until it reaches 0 GWh of demand in 2027. Assumed to consume 599 MW in 2022, 479 MW in 2023, 359 in 2024, 239 in 2025, and 120 MW in 2026.
Thermal decommissioning	Yes	Yes	This sensitivity explores the situation where one of the two Combined Cycle Gas Turbines shuts down in 2023.	Generation from one of the Combined Cycle Gas Turbines stops at the beginning of 2023 (equivalent to 360 MW of generation).
Delayed build times	Yes	Yes	This sensitivity explores the situation where the commissioning date for new generation is delayed by one year.	Commissioning dates for all new generation is delayed by one year.
Reduced generation availability	Yes	Yes	This sensitivity explores the impact of a reduction in electricity supply. This sensitivity is designed to indirectly account for internal and external influences that may reduce the output of electricity generation. External influences include effects such as reduction in geothermal field pressure, systemic changes to inflow patterns, etc. Internal influences include effects such as statistical errors in historical generation data and forecast errors for new generation.	In the calculation of energy margins, all non-thermal generation energy contribution is reduced by 5%. In the calculation of capacity margins, all non-thermal generation capacity factors are reduced by 5%.
Future renewable generation increase	Yes	Yes	This sensitivity explores the impact of an increase in future renewable generation supply. This accounts for a situation where the amount of future renewable generation is greater than expected. This covers the situation where renewable generation projects are developed in *addition* to those already modelled in this assessment. Typically, renewable generation projects are signalled many years in advance before they are actively developed and are easily tracked. This may not always hold true in the future. In particular, solar generation projects appear to have lower barriers to gaining resource consent and short lead times from concept to development.	In the calculation of energy margins, all renewable generation energy contribution is increased by 5%. In the calculation of capacity margins, all renewable generation capacity factors are increased by 5%.
Change in peak transmission pricing	No	Yes	This sensitivity explores a change in peak transmission pricing which results in distributors and large, grid-connected consumers reducing or stopping their load control or demand response activities (currently employed to reduce their share of transmission interconnection charges). We expect that this loss will be temporary	We assume winter peak demand increases (from forecast levels) in 2023 by 158.5 MW in the North Island and 173.5 MW in the South Island[18]. In 2024, this increase in winter peak demand is

[18] This aligns with a report by Concept Consulting investigating the impact of possible changes to peak transmission pricing on winter capacity margins. Concept Consulting's base case projection estimated that winter peak demand would increase by 332 MW. Two other sensitivities were also explored where winter peak demand increased by 548 MW and 659 MW.

Sensitivity	Affects Energy	Affects Capacity	Rationale	Assumptions
			as other arrangements are likely to be made for the use of this load control to, for example, manage wholesale risk or local transmission constraints.	reduced by 50%, and in 2025 winter peak demand returns to forecast levels.
Delayed demand growth due to Covid-19	Yes	Yes	This sensitivity explores the impact of delayed demand growth that could occur as a result of Covid-19. It is an early, 'first-cut' indication of what may happen (and subject to change). We plan to do further work in this area, with the intent of publishing additional refined Covid-19 sensitivities, in the second half of this year.	Growth in energy demand is stalled from March 2020, and then after 18 months the growth rate returns to normal pre-Covid-19 levels (with a time constant of six months). We acknowledge that there are a range of other possible outcomes as a result of Covid-19. Demand growth may rebound more strongly and earlier than expected. Alternatively, demand growth may be delayed for some number of years and further reduced by closure of a major industrial plant. As such this assumption should be viewed with some degree of caution.

2.1 ENERGY MARGIN SENSITIVITIES

2.1.1 NZAS Closure Sensitivity

New Zealand Winter Energy Margin

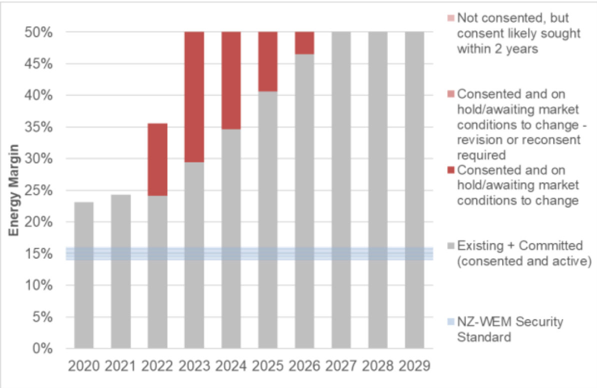

Figure 20: NZ WEM – NZAS closure and Low Demand

South Island Winter Energy Margin

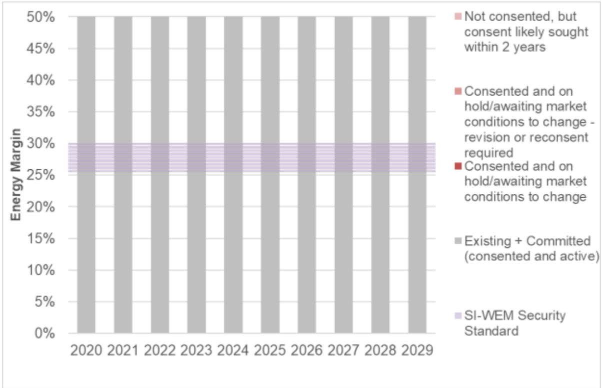

Figure 21: SI WEM – NZAS closure and Low Demand

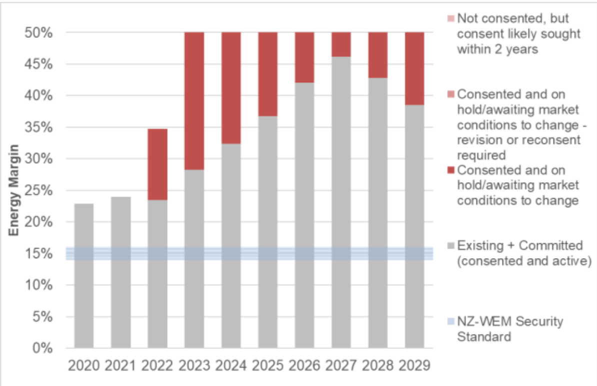

Figure 22: NZ WEM – NZAS closure and Medium Demand

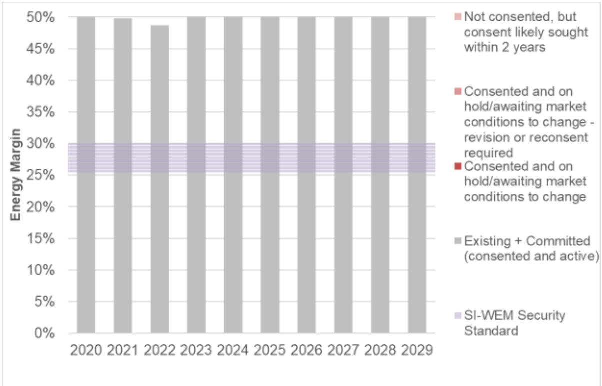

Figure 23: SI WEM – NZAS closure and Medium Demand

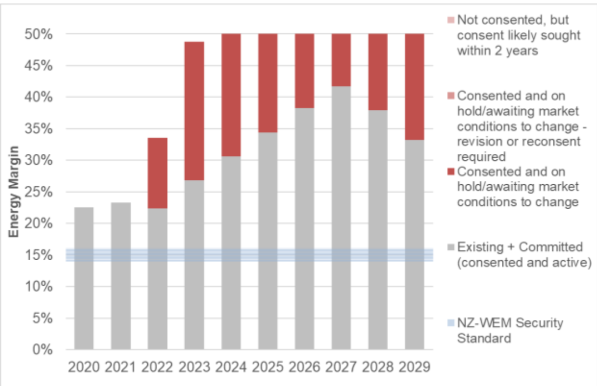

Figure 24: NZ WEM – NZAS closure and High Demand

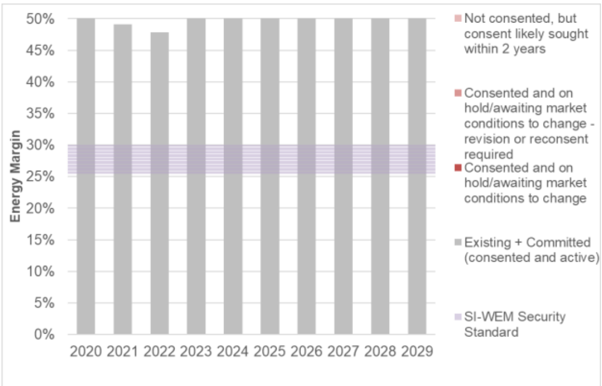

Figure 25: SI WEM – NZAS closure and High Demand

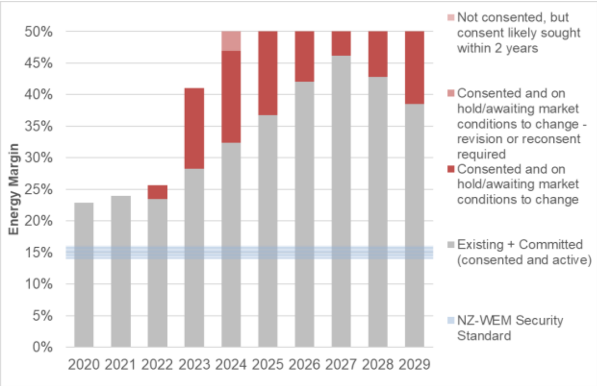

Figure 26: NZ WEM – NZAS closure and Thermal Constraints

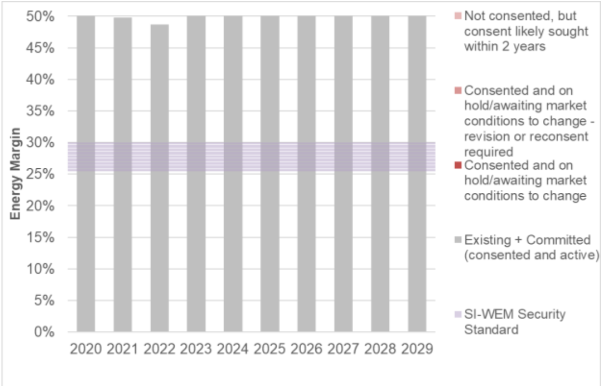

Figure 27: SI WEM – NZAS closure and Thermal Constraints

2.1.2 Thermal Decommissioning Sensitivity

New Zealand Winter Energy Margin

South Island Winter Energy Margin

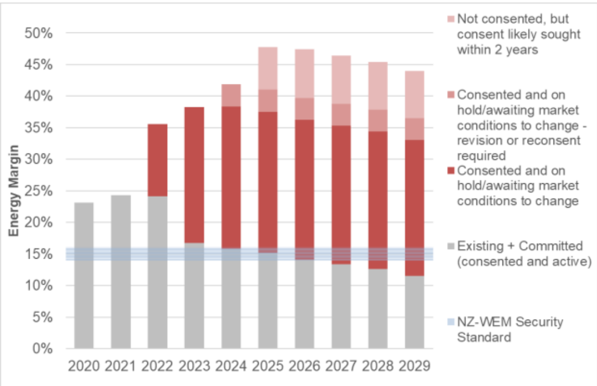

Figure 28: NZ WEM – Thermal decommissioning and Low Demand

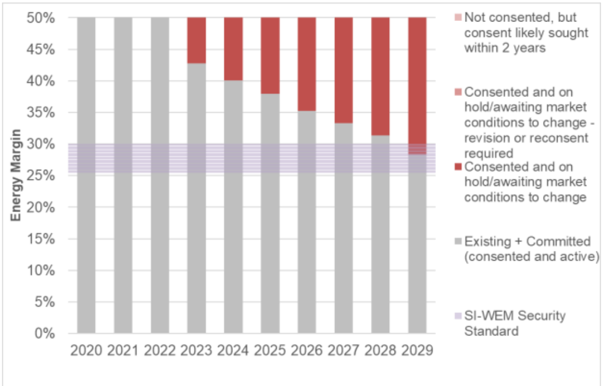

Figure 29: SI WEM – Thermal decommissioning and Low Demand

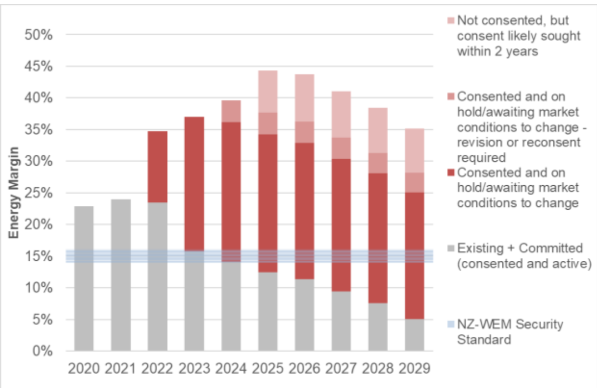

Figure 30: NZ WEM – Thermal decommissioning and Medium Demand

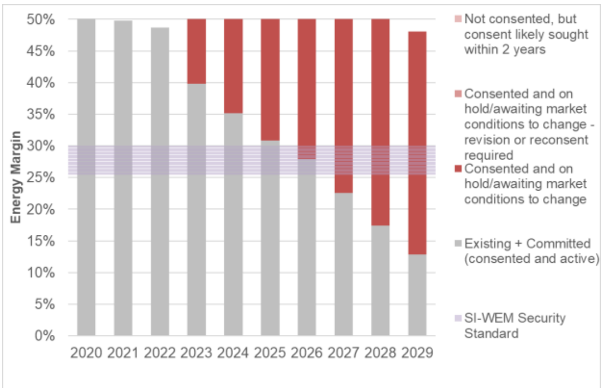

Figure 31: SI WEM – Thermal decommissioning and Medium Demand

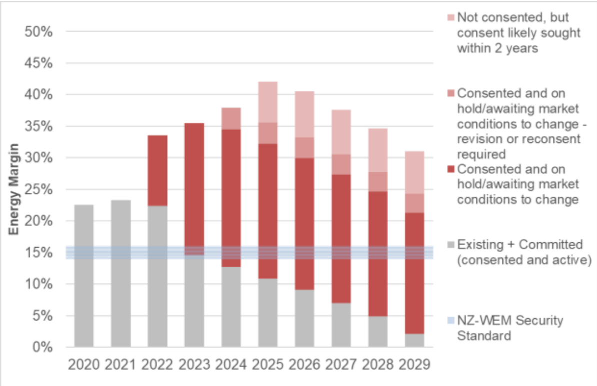

Figure 32: NZ WEM – Thermal decommissioning and High Demand

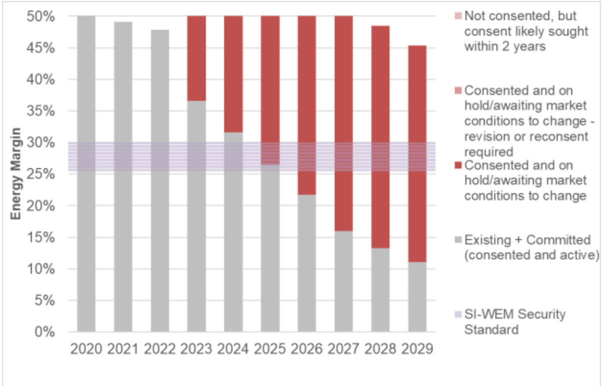

Figure 33: SI WEM – Thermal decommissioning and High Demand

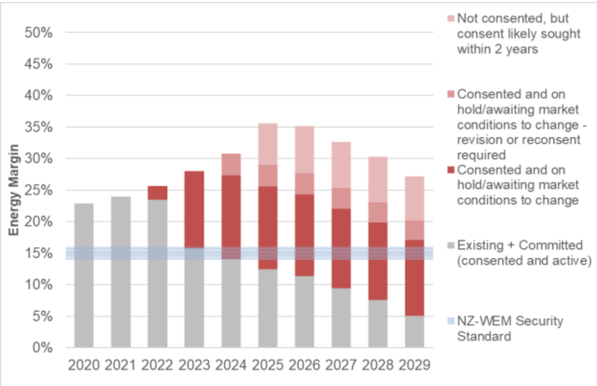

Figure 34: NZ WEM – Thermal decommissioning and Thermal Constraints

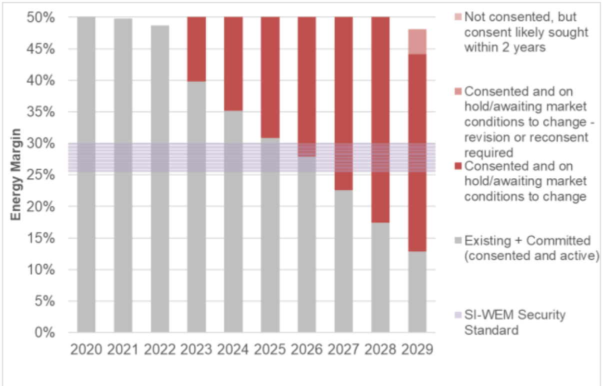

Figure 35: SI WEM – Thermal decommissioning and Thermal Constraints

2.1.3 Delayed Build Times Sensitivity

New Zealand Winter Energy Margin

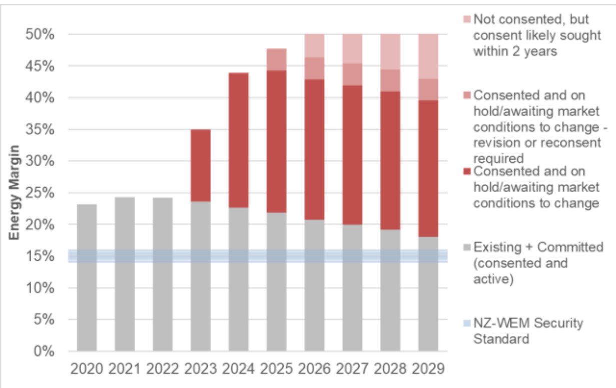

Figure 36: NZ WEM – Delayed build times and Low Demand

South Island Winter Energy Margin

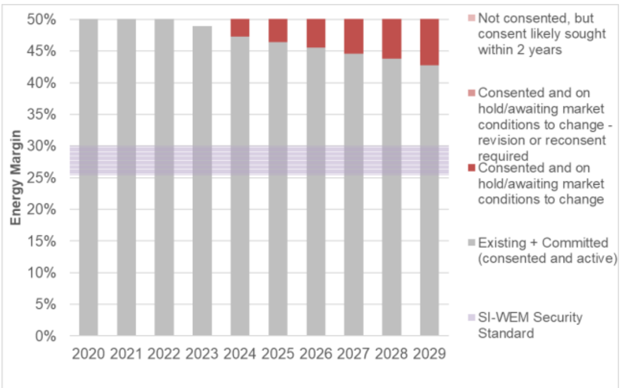

Figure 37: SI WEM – Delayed build times and Low Demand

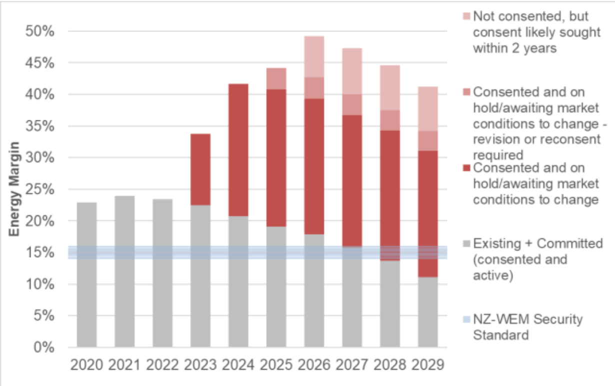

Figure 38: NZ WEM – Delayed build times and Medium Demand

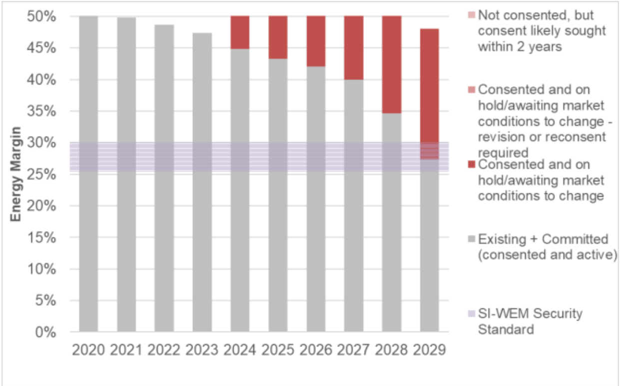

Figure 39: SI WEM – Delayed build times and Medium Demand

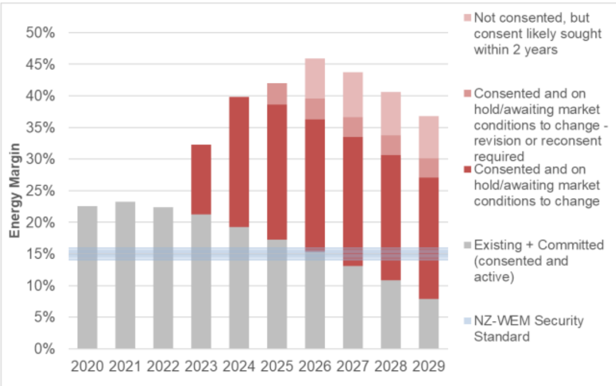

Figure 40: NZ WEM – Delayed build times and High Demand

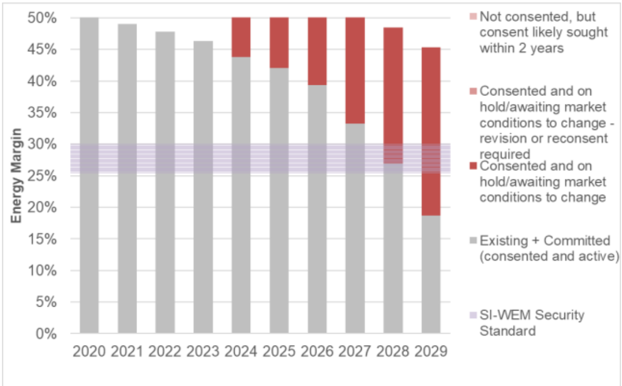

Figure 41: SI WEM – Delayed build times and High Demand

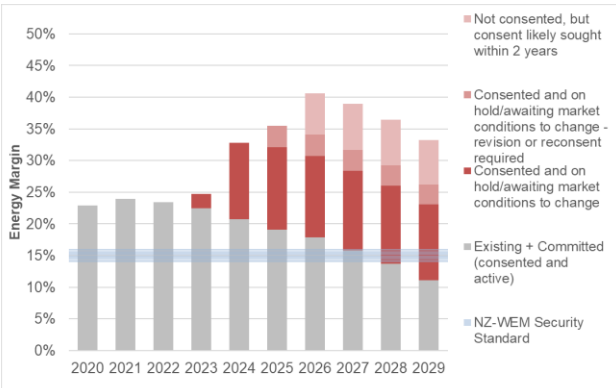

Figure 42: NZ WEM – Delayed build times and Thermal Constraints

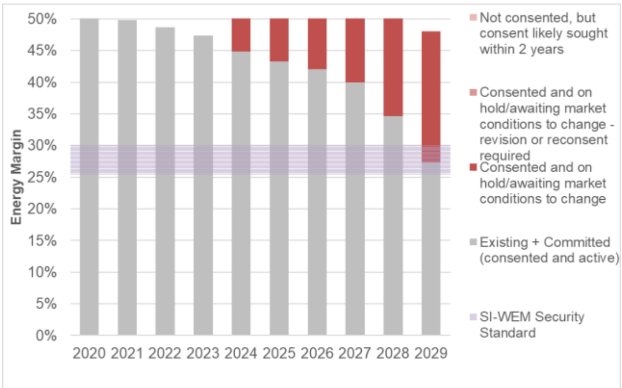

Figure 43: SI WEM – Delayed build times and Thermal Constraints

2.1.4 Reduced Generation Availability Sensitivity

New Zealand Winter Energy Margin

South Island Winter Energy Margin

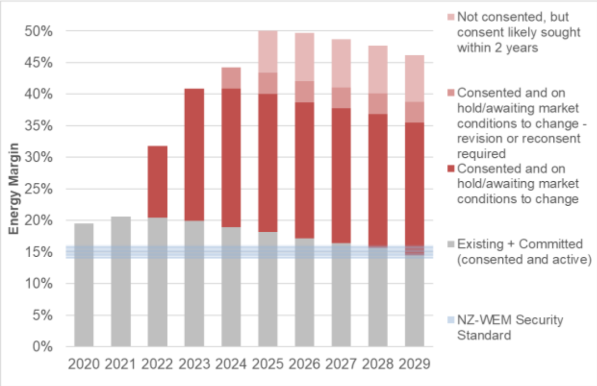

Figure 44: NZ WEM – Reduced generation availability and Low Demand

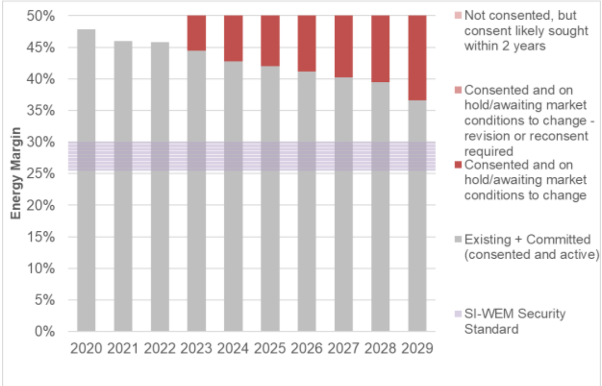

Figure 45: SI WEM – Reduced generation availability and Low Demand

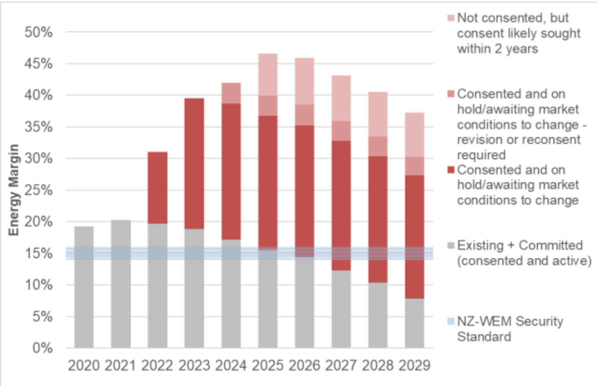

Figure 46: NZ WEM – Reduced generation availability and Medium Demand

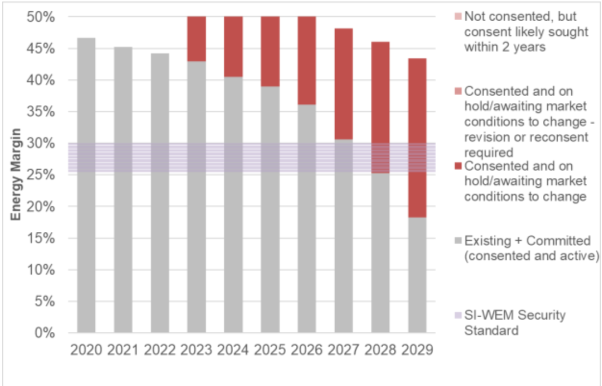

Figure 47: SI WEM – Reduced generation availability and Medium Demand

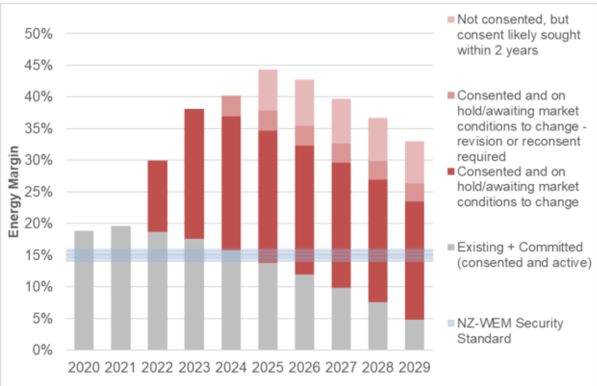

Figure 48: NZ WEM – Reduced generation availability and High Demand

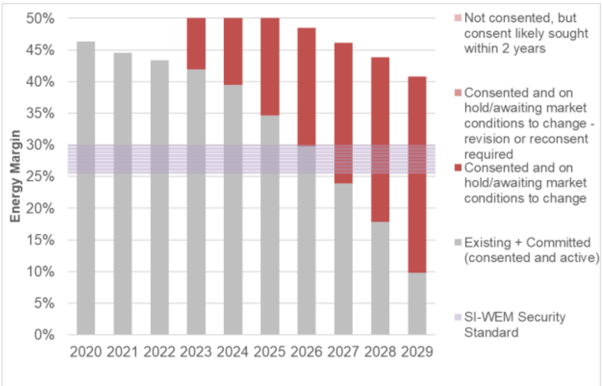

Figure 49: SI WEM – Reduced generation availability and High Demand

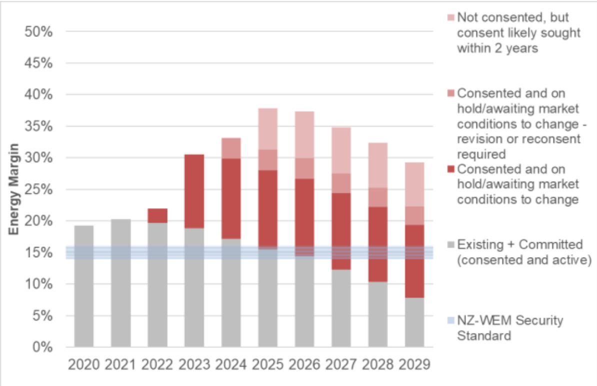

Figure 50: NZ WEM – Reduced generation availability and Thermal Constraints

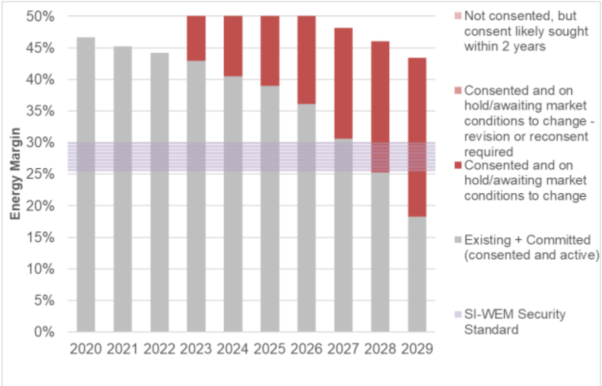

Figure 51: SI WEM – Reduced generation availability and Thermal Constraints

2.1.5 Future Renewable Generation Increase Sensitivity

New Zealand Winter Energy Margin

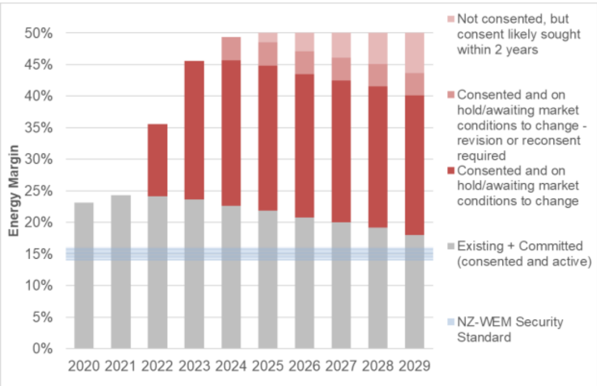

Figure 52: NZ WEM – Future renewable generation increase and Low Demand

South Island Winter Energy Margin

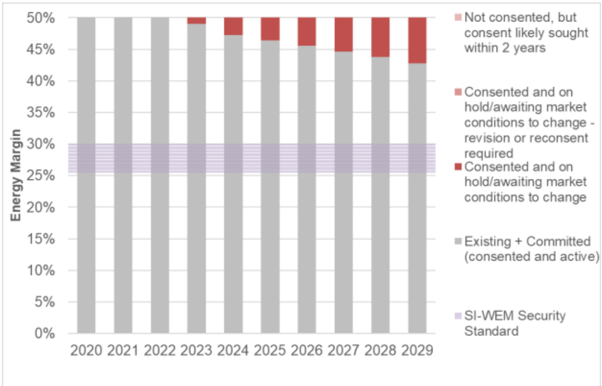

Figure 53: SI WEM – Future renewable generation increase and Low Demand

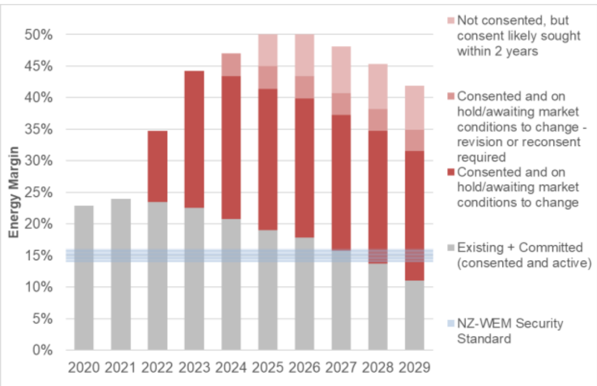

Figure 54: NZ WEM –Future renewable generation increase and Medium Demand

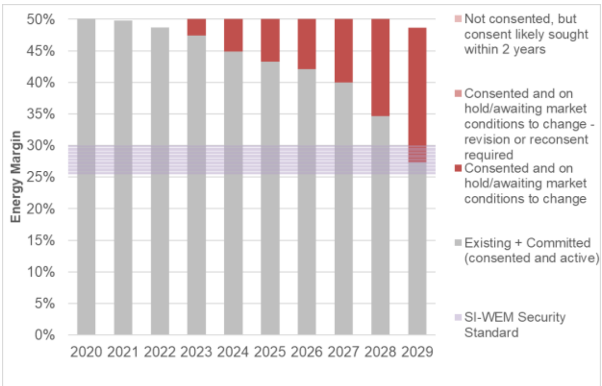

Figure 55: SI WEM –Future renewable generation increase and Medium Demand

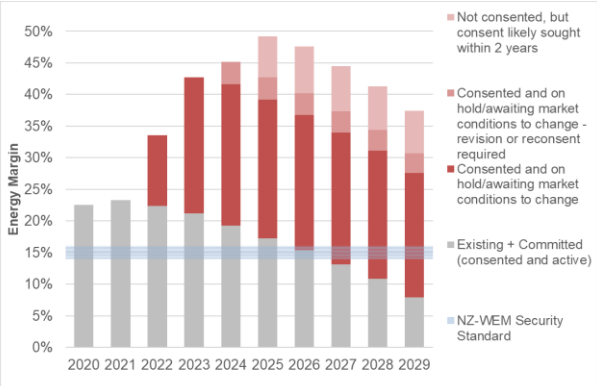

Figure 56: NZ WEM – Future renewable generation increase and High Demand

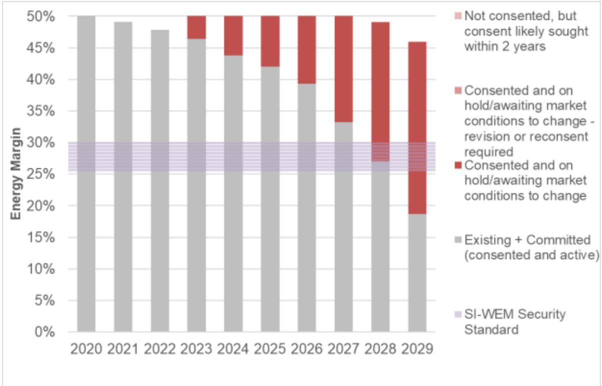

Figure 57: SI WEM – Future renewable generation increase and High Demand

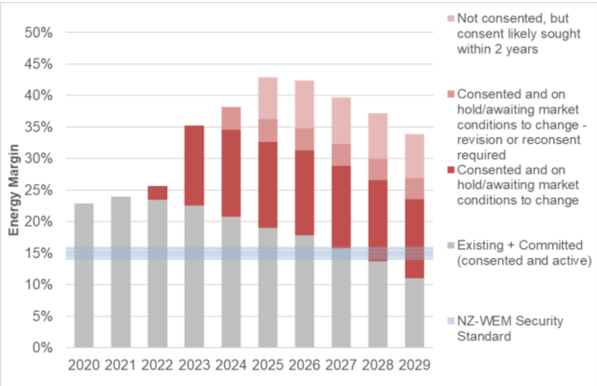

Figure 58: NZ WEM – Future renewable generation increase and Thermal Constraints

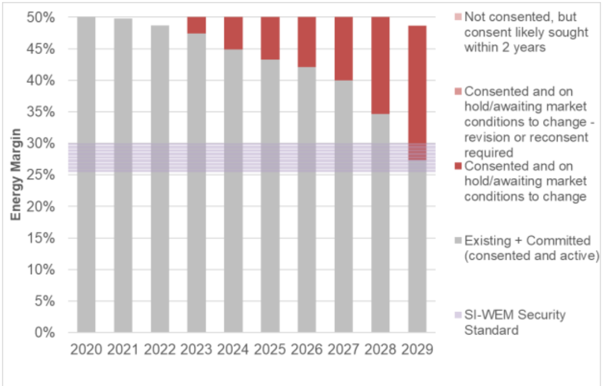

Figure 59: SI WEM – Future renewable generation increase and Thermal Constraints

2.1.6 Delayed demand growth due to Covid-19

New Zealand Winter Energy Margin

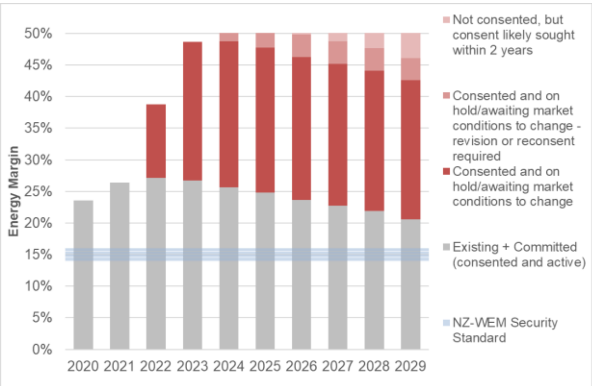

Figure 60: NZ WEM – Delayed demand growth due to Covid-19 and Low Demand

South Island Winter Energy Margin

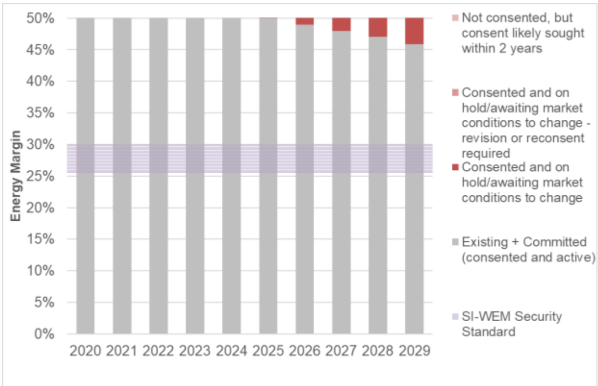

Figure 61: SI WEM – Delayed demand growth due to Covid-19 and Low Demand

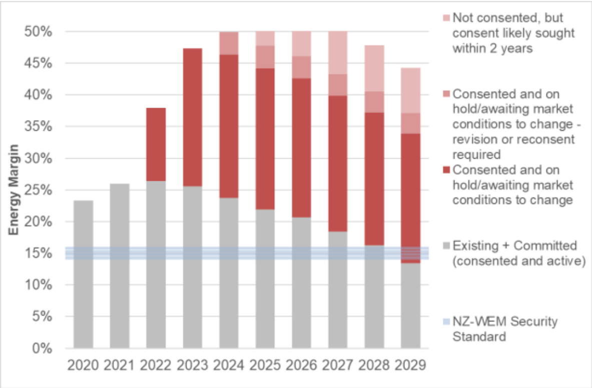

Figure 62: NZ WEM – Delayed demand growth due to Covid-19 and Medium Demand

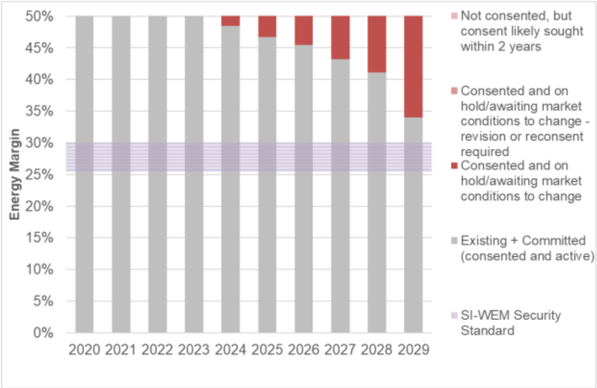

Figure 63: SI WEM – Delayed demand growth due to Covid-19 and Medium Demand

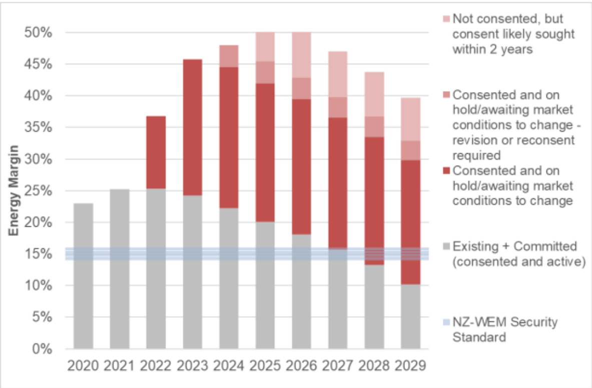

Figure 64: NZ WEM – Delayed demand growth due to Covid-19 and High Demand

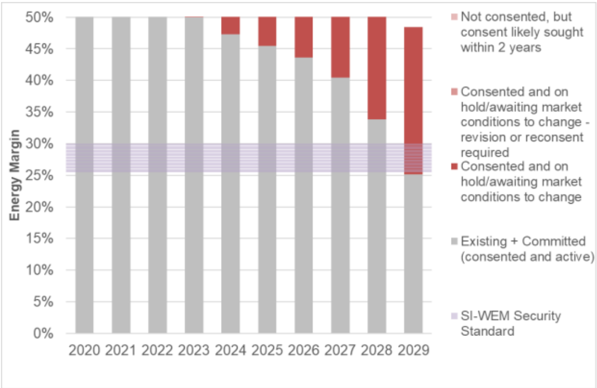

Figure 65: SI WEM – Delayed demand growth due to Covid-19 and High Demand

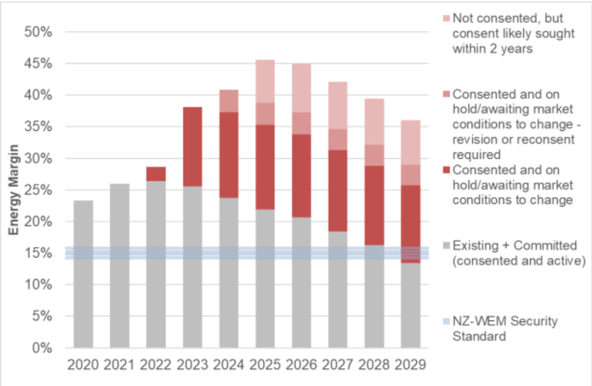

Figure 66: NZ WEM – Delayed demand growth due to Covid-19 and Thermal Constraints

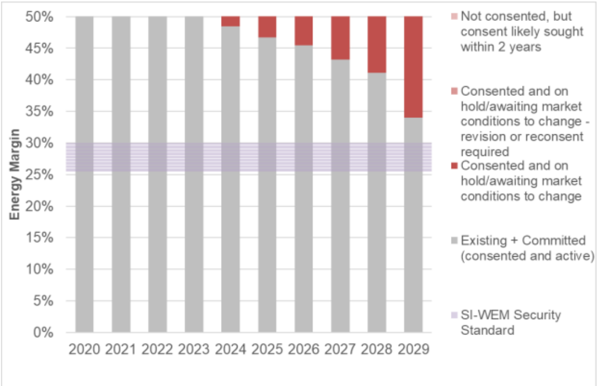

Figure 67: SI WEM – Delayed demand growth due to Covid-19 and Thermal Constraints

2.2 CAPACITY MARGIN SENSITIVITIES

2.2.1 NZAS Closure Sensitivity

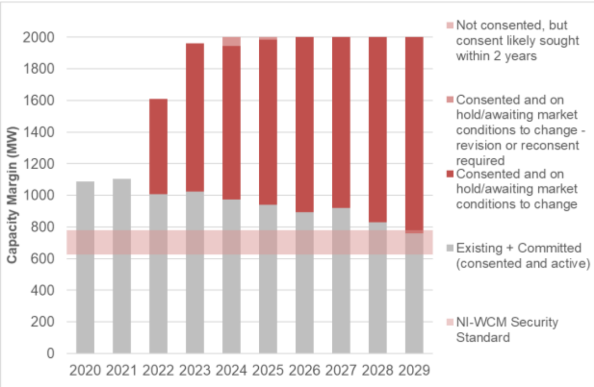

Figure 68: NI WCM – NZAS closure and Low Demand

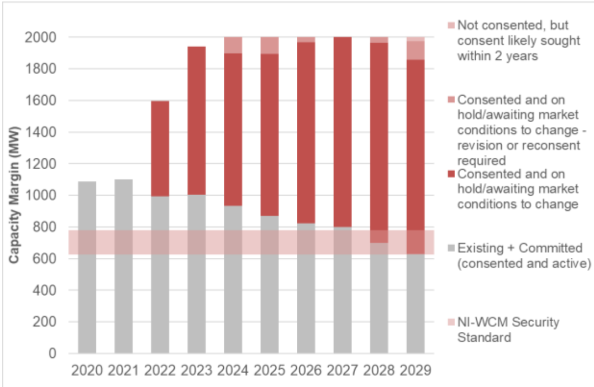

Figure 69: NI WCM – NZAS closure and Medium Demand

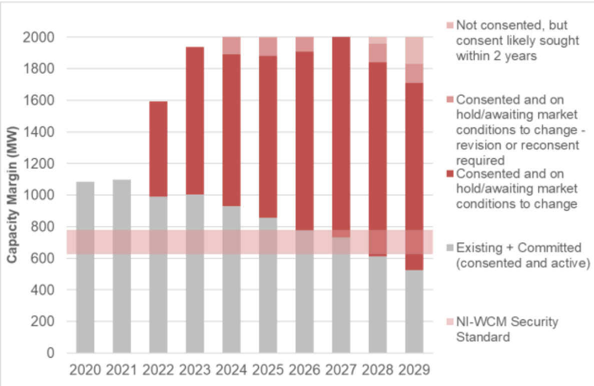

Figure 70: NI WCM – NZAS closure and High Demand

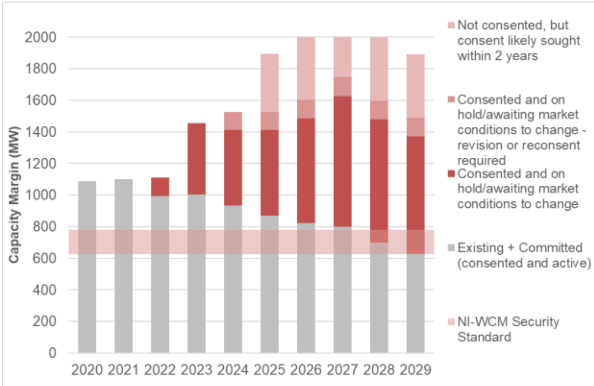

Figure 71: NI WCM – NZAS closure and Thermal Constraints

2.2.2 Thermal Decommissioning Sensitivity

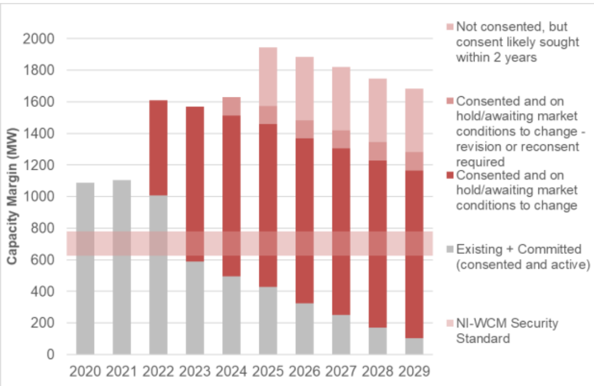

Figure 72: NI WCM – Thermal decommissioning and Low Demand

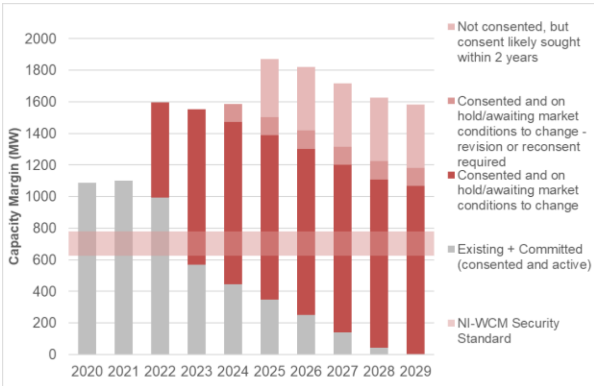

Figure 73: NI WCM – Thermal decommissioning and Medium Demand

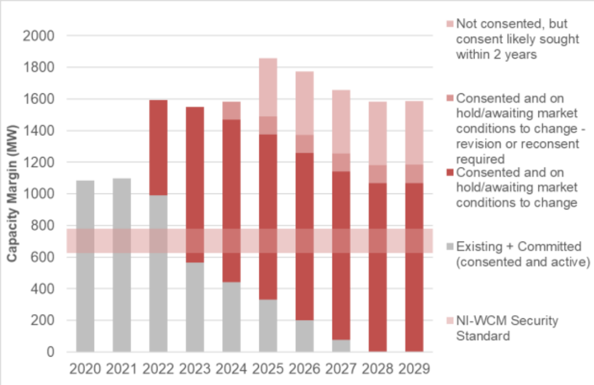

Figure 74: NI WCM – Thermal decommissioning and High Demand

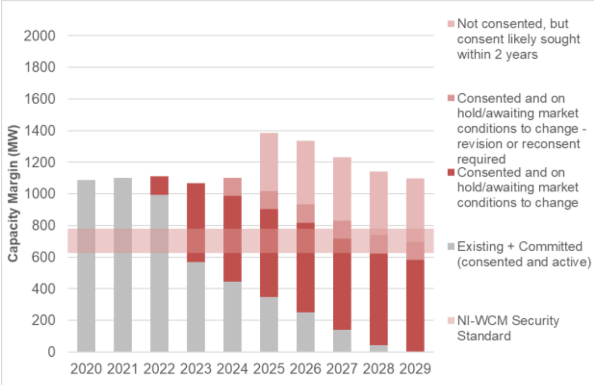

Figure 75: NI WCM – Thermal decommissioning and Thermal Constraints

2.2.3 Delayed Build Time Sensitivity

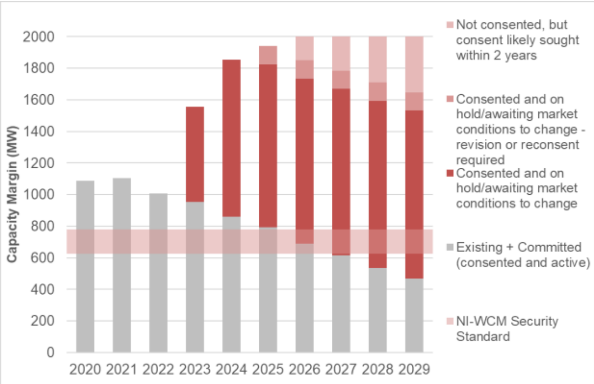

Figure 76: NI WCM – Delayed build time and Low Demand

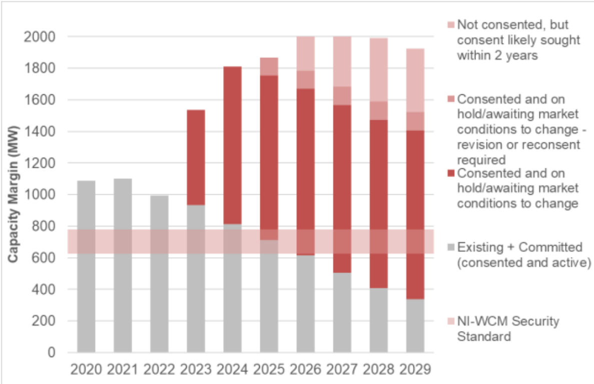

Figure 77: NI WCM – Delayed build time and Medium Demand

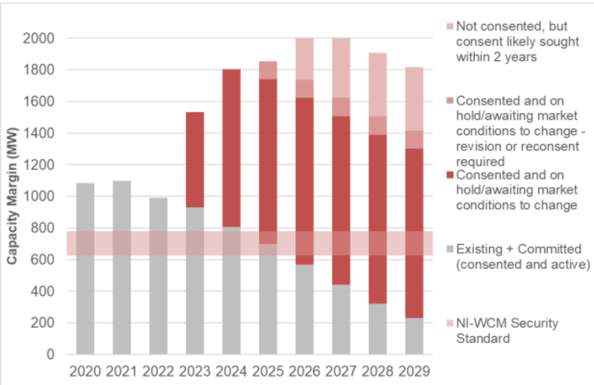

Figure 78: NI WCM – Delayed build time and High Demand

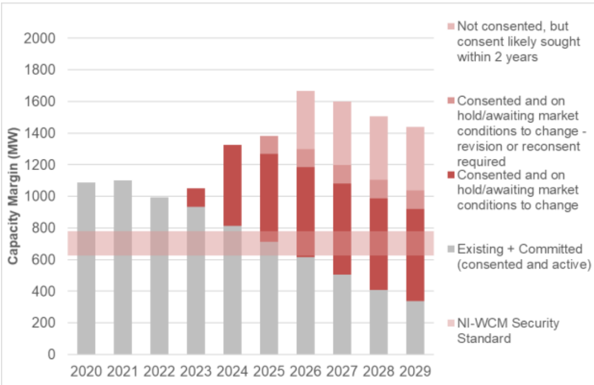

Figure 79: NI WCM – Delayed build time and Thermal Constraints

2.2.4 Reduced Generation Availability Sensitivity

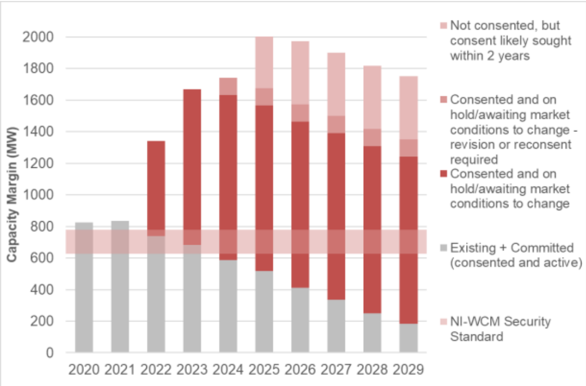

Figure 80: NI WCM – Reduced generation availability and Low Demand

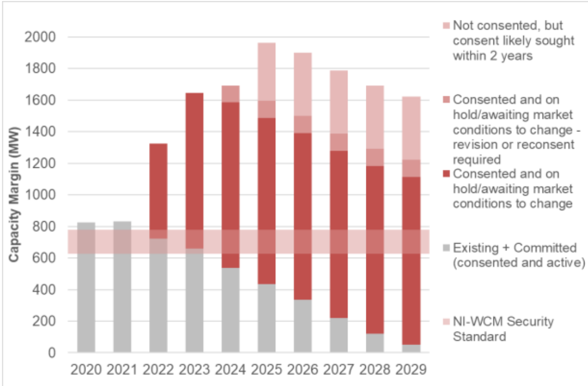

Figure 81: NI WCM – Reduced generation availability and Medium Demand

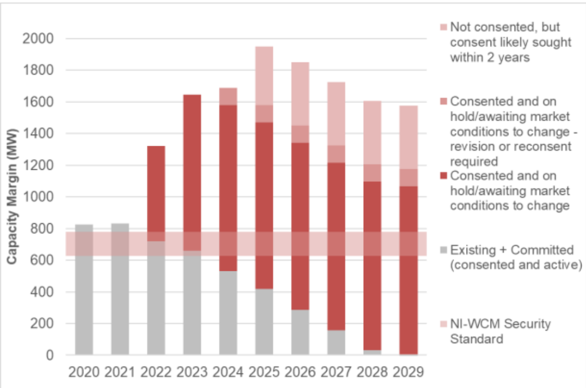

Figure 82: NI WCM – Reduced generation availability and High Demand

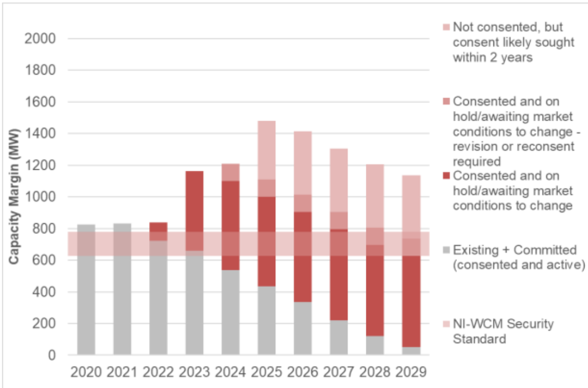

Figure 83: NI WCM – Reduced generation availability and Thermal Constraints

2.2.5 Future Renewable Generation Increase Sensitivity

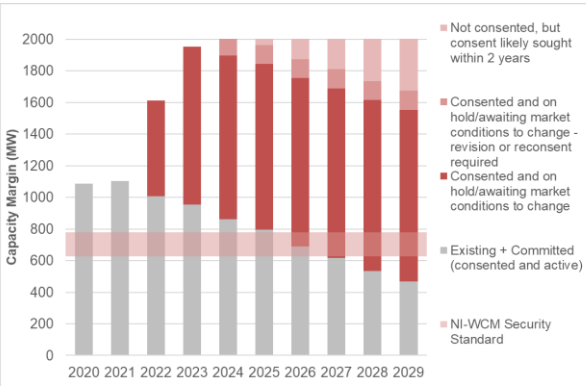

Figure 84: NI WCM – Future renewable generation increase and Low Demand

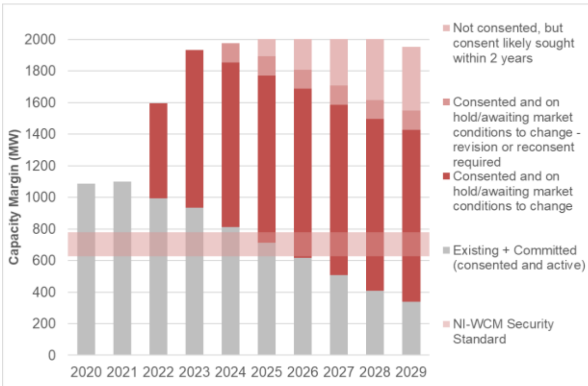

Figure 85: NI WCM – Future renewable generation increase and Medium Demand

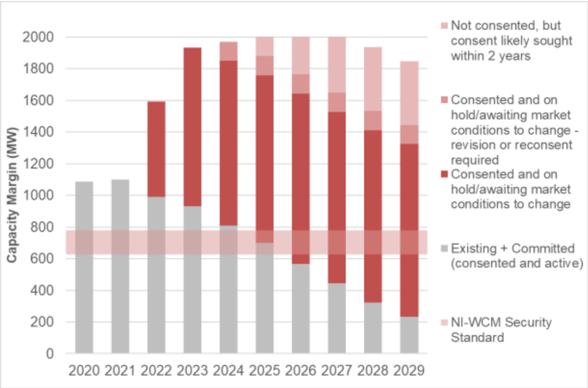

Figure 86: NI WCM – Future renewable generation increase and High Demand

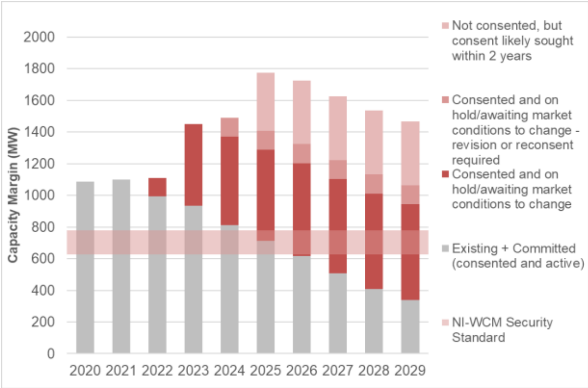

Figure 87: NI WCM – Future renewable generation increase and Thermal Constraints

2.2.6 Change in Peak Transmission Pricing Sensitivity

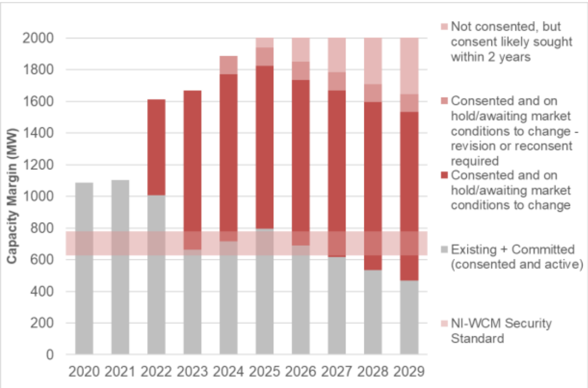

Figure 88: NI WCM – Change in peak transmission pricing and Low Demand

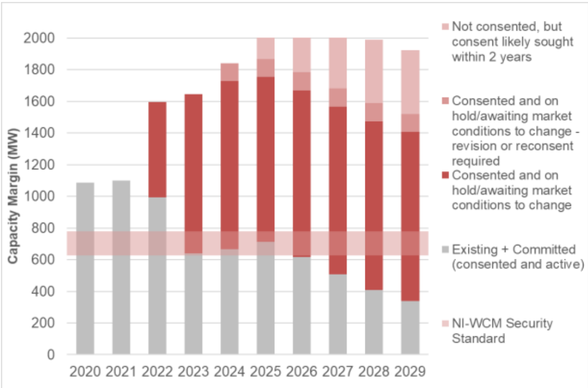

Figure 89: NI WCM – Change in peak transmission pricing and Medium Demand

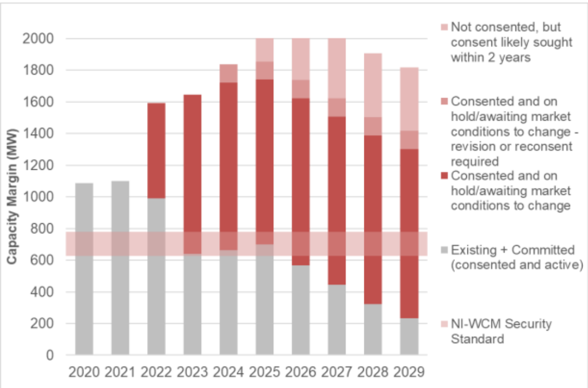

Figure 90: NI WCM – Change in peak transmission pricing and High Demand

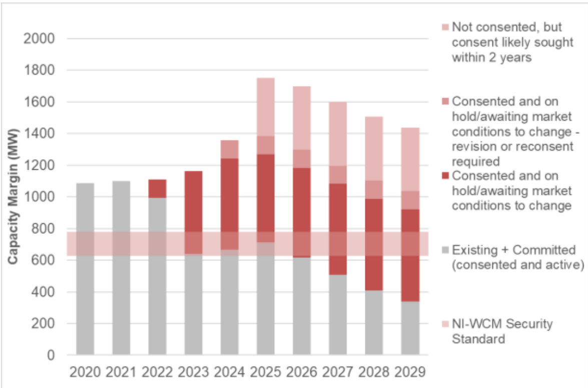

Figure 91: NI WCM – Change in peak transmission pricing and Thermal Constraints

2.2.7 Delayed demand growth due to Covid-19

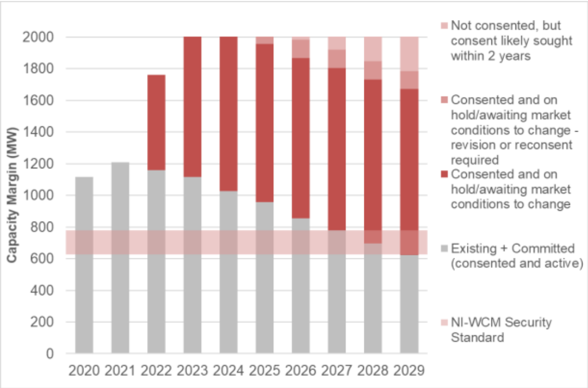

Figure 92: NI WCM – Delayed demand growth due to Covid-19 and Low Demand

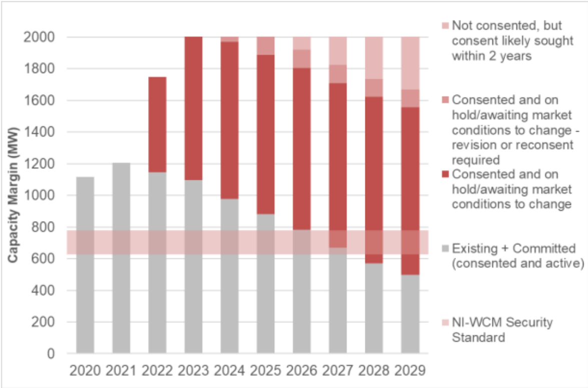

Figure 93: NI WCM – Delayed demand growth due to Covid-19 and Medium Demand

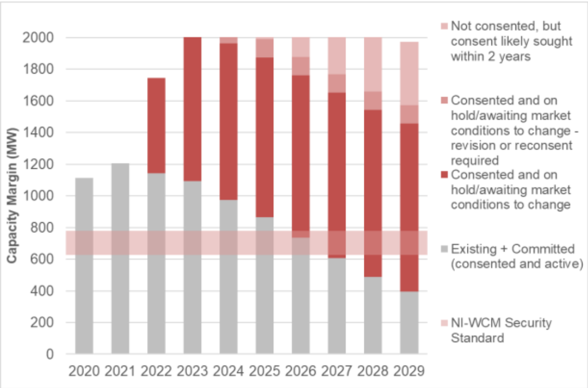

Figure 94: NI WCM – Delayed demand growth due to Covid-19 and High Demand

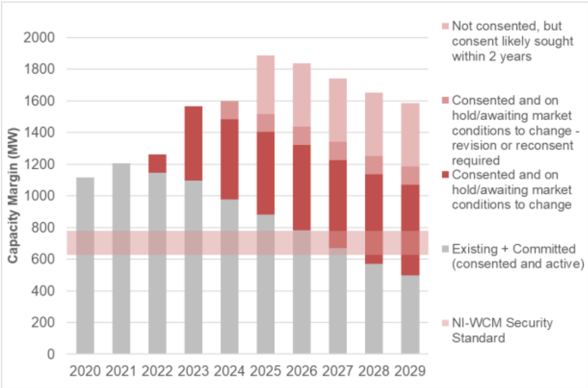

Figure 95: NI WCM – Delayed demand growth due to Covid-19 and Thermal Constraints

Appendix 3: METHODOLOGY

3.1 SECURITY OF SUPPLY STANDARDS AND INTERPRETATION

The security of supply assessment enables interested parties to compare projected winter energy and capacity margins over the next 10 years. The margins that define the security of supply standards used in this assessment are determined by the Electricity Authority and are documented within the Code.[19] The Electricity Authority derived the margins in 2012 using a probabilistic analysis.[20] The analysis sought to determine:

- the efficient level of North Island peaking capacity, defined as the level that minimises the sum of the expected societal cost of capacity shortage plus the cost of providing peaking generation capacity
- the efficient level of national winter energy supply, defined as the level that minimises the sum of the expected societal cost of energy shortage plus the cost of providing thermal firming capacity
- equivalently, the efficient level of South Island winter energy supply.

The current security of supply standards are:

- a WEM of 14-16 per cent for New Zealand
- a WEM of 25.5-30 per cent for the South Island
- a WCM of 630-780 MW for the North Island.

The Electricity Authority suggests that assessed margins should be interpreted as:

- A North Island WCM below 630 MW indicates an inefficiently low level of capacity; the cost of adding more capacity (or instantaneous reserves) would be justified by the reduction in shortage costs at times of insufficient capacity (or instantaneous reserves)
- A North Island WCM between 630 and 780 MW indicates an approximate efficient level of capacity
- A North Island WCM above 780 MW indicates a capacity level that is inefficiently high in terms of the trade-off between supply costs and the cost of shortage at times of insufficient capacity (but may still be efficient for other reasons).

Assessed WEMs should be interpreted in a similar fashion (with the exception that any additional instantaneous reserves supply no energy, and therefore would not impact the margin).

The Electricity Authority's security of supply standards are expressed as winter requirements, reflecting when New Zealand's power system demand is highest and the impact of low thermal plant availability and low hydro inflows are greatest.

[19] See Part 7, clause 7.3 of the Electricity Industry Participation Code 2010 for more information

[20] http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/security-of-supply-standards/consultations/#c13932

3.2 Energy Margin Assessment

There are two Winter Energy Margins. The New Zealand Winter Energy Margin is calculated as:

$$NZ\ WEM = \left(\frac{New\ Zealand\ expected\ energy\ supply}{New\ Zealand\ expected\ energy\ demand} - 1\right) \times 100\%$$

The South Island Winter Energy Margin is calculated as:

$$SI\ WEM = \left(\frac{South\ Island\ expected\ energy\ supply + expected\ HVDC\ transfers\ south}{South\ Island\ expected\ energy\ demand} - 1\right) \times 100\%$$

Table 3: Summarising the New Zealand WEM components

Component	Comprises of	Description
New Zealand expected energy supply (GWh)	Thermal GWh	Maximum expected thermal generation available to meet winter (1 April to 30 September) energy demand allowing for forced and scheduled outages, available fuel supply and operational and transmission constraints.
	Mean Hydro GWh	Expected winter (1 April to 30 September) hydro generation based on mean inflows and expected 1 April start storage of 2,750 GWh.
	Other GWh	Expected winter (1 April to 30 September) energy available from cogeneration[21], geothermal and wind generation based on long-run average supply.
New Zealand expected energy demand (GWh)	NZ Energy Demand GWh	Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).

Table 4: Summarising the South Island WEM components

Component	Comprises	Description
South Island expected energy supply (GWh)	Mean Hydro GWh	Expected winter (1 April to 30 September) hydro generation based on mean inflows and assumed 1 April start storage of 2,400 GWh.
	Other GWh	Expected winter (1 April to 30 September) wind generation based on long-run average supply.
Expected HVDC transfers south (GWh)	HVDC GWh	Expected winter (1 April to 30 September) HVDC transfers received in the South Island.
South Island expected energy demand (GWh)	SI Energy Demand GWh	Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).

[21] Cogeneration has not been treated as thermal generation as it is assumed the primary fuel supply is based on industrial processes and not controlled in the same way as major thermal generators.

3.3 Capacity Margin Assessment

The North Island Winter Capacity Margin is calculated as:

$$NI\ WCM = North\ Island\ expected\ capacity - North\ Island\ expected\ demand$$
$$+\ expected\ HVDC\ transfer\ north\ (function\ of\ SI\ capacity - SI\ demand)$$

Table 5: Summarising the North Island WCM components

Component	Comprises	Description
North Island expected capacity (MW)	NI Thermal MW	Installed capacity of North Island thermal generation sources allowing for forced and scheduled outages, available fuel supply and operational and transmission constraints.
	NI Hydro MW	Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and de-rated to account for energy and other constraints which affect output during peak times.
	NI Other MW	Expected winter peak generation from geothermal, wind, cogeneration and uncontrolled hydro scheme generation.
North Island expected demand (MW)	NI Peak Demand MW	Expected average of the highest 100 hours of demand in winter inclusive of losses. This is referred to as H100 NI demand.
	NI Demand Response and Interruptible Load MW	Expected demand response and interruptible load over the highest 100 hours of demand during winter peak. This is subtracted from NI Peak Demand to calculate NI expected demand.
Expected HVDC transfer north	South Island MW	The net amount of MW the South Island can supply to the North Island during peak periods. This is a similar calculation to above (supply capacity minus H100 NI demand); however, also takes into account HVDC transfer capability.

Appendix 4: Detailed Supply Assumptions

The calculation of winter margins requires some assumptions about the capacity and availability of existing and new generation as well as the contribution of the HVDC. Many of the assumptions discussed are based on the Security Standards Assumption Document (SSAD) published by the Electricity Authority.

4.1 Existing Generation

The following tables summarises the existing grid-connected and large embedded generation[22] that is used in the assessment. Other (non-modelled, smaller) embedded generation is also included when calculating security margins and contributions are sourced from the winter demand forecast (refer to Appendix 6).

Each generator has an energy and capacity rating which includes allowances for scheduled and forced outages.

Table 6: Existing North Island Supply

Plant	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Aniwhenua	Hydro - Inflexible run-of-river	25	18	62	72.0%	57.0%
Arapuni	Controlled Hydro	192	See Waikato scheme			
Aratiatia	Controlled Hydro	78	See Waikato scheme			
Atiamuri	Controlled Hydro	74	See Waikato scheme			
Edgecumbe	Thermal - Cogen	10	6	26	61.0%	60.0%
Geothermal Developments Limited	Geothermal	9	8	37	91.7%	94.0%
Glenbrook	Thermal - Cogen	74	45	211	61.0%	65.0%
Huntly Rankines	Thermal - Coal	480	466	1,962	97.0%	93.3%
Huntly U5	Thermal - Gas	385	373	1,595	97.0%	94.6%
Huntly U6	Thermal - Gas	45	44	186	97.0%	94.6%
Kaimai	Hydro - Flexible run-of-river	38	31	82	81.2%	49.3%
Kaitawa	Controlled Hydro	36	See Waikaremoana scheme			
Kapuni	Thermal - Cogen	25	15	84	61.0%	77.0%

[22] Assumed capacity and energy contributions for large embedded generation are based on information either provided by participants or from Transpower's SCADA system.

Plant	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Karapiro	Controlled Hydro	96	See Waikato scheme			
Kawerau	Geothermal	106	97	447	91.7%	96.2%
Kawerau Onepu	Geothermal	60	55	208	91.7%	79.0%
Kinleith	Thermal - Cogen	40	24	124	61.0%	71.0%
Kiwi Dairy, Hawera (Whareroa)	Thermal - Cogen	70	43	202	61.0%	66.0%
Mangahao	Hydro - Inflexible run-of-river	42	30	72	72.0%	39.0%
Maraetai	Controlled Hydro	352	See Waikato scheme			
Matahina	Controlled Hydro	80	66	133	98.0%	38.0%
McKee	Thermal - Gas	100	97	414	97.0%	94.6%
Mill Creek	Wind	60	15	119	25.0%	45.0%
Mokai	Geothermal	112	103	450	91.7%	91.7%
Nga Awa Purua	Geothermal	135	124	574	91.7%	97.1%
Ngatamariki	Geothermal	85	78	360	91.7%	96.7%
Ngawha	Geothermal	26	24	104	91.7%	91.0%
Ohaaki	Geothermal	40	37	140	91.7%	80.0%
Ohakuri	Controlled Hydro	106	See Waikato scheme			
Patea	Controlled Hydro	32.2	27	53	98.0%	37.2%
Piripaua	Controlled Hydro	44	See Waikaremoana scheme			
Poihipi	Geothermal	55	50	222	91.7%	92.0%
Rangipo	Hydro - Inflexible run-of-river	120	86	284	72.0%	54.0%
Rotokawa	Geothermal	34.5	32	142	91.7%	94.0%
Stratford Peaker	Thermal - Gas	200	194	829	97.0%	94.6%
Tararua I	Wind	31.68	8	57	25.0%	41.1%
Tararua II	Wind	36.3	9	66	25.0%	41.6%
Tararua III	Wind	93	23	161	25.0%	39.5%
TCC	Thermal - Gas	377	366	1,562	97.0%	94.6%
Te Ahi O Maui	Geothermal	27	25	106	91.7%	90.0%
Te Āpiti	Wind	90	23	130	25.0%	33.0%
Te Huka	Geothermal	28	26	117	91.7%	95.0%
Te Mihi	Geothermal	166	152	669	91.7%	92.0%

Plant	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Te Rapa	Thermal - Cogen	44	27	164	61.0%	85.1%
Te Rere Hau	Wind	48.5	12	56	25.0%	26.2%
Te Uku	Wind	67	17	99	25.0%	33.9%
Tokaanu	Controlled Hydro	240	216	414	98.0%	39.4%
Tuai	Controlled Hydro	59	See Waikaremoana scheme			
Waipapa	Controlled Hydro	54	See Waikato scheme			
Wairakei incl. binary	Geothermal	132	121	549	91.7%	95.0%
West Wind	Wind	142	36	257	25.0%	41.3%
Whakamaru	Controlled Hydro	112	See Waikato scheme			
Wheao	Hydro - Flexible run-of-river	24	19	54	81.2%	51.4%
Whirinaki	Thermal - Diesel	155	150	30	97.0%	4.4%

* Energy and capacity contributions of this plant are detailed in the aggregated hydro schemes shown in Table 8.

Table 7: Existing South Island Supply

Scheme	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Aviemore	Controlled Hydro	220	See Waitaki scheme			
Benmore	Controlled Hydro	540	See Waitaki scheme			
Branch	Hydro - Inflexible run-of-river	11	8	25	72.0%	50.9%
Clyde	Controlled Hydro	432	See Clutha scheme			
Cobb	Controlled Hydro	32	31	93	98.0%	66.0%
Coleridge	Controlled Hydro	39	38	130	98.0%	75.8%
Deep Stream	Hydro - Flexible run-of-river	6	5	12	81.2%	43.8%
Highbank/Montalto	Hydro - Flexible run-of-river	26.8	22	48	81.2%	40.9%

Scheme	Type	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Kumara/Dillmans/Duffers	Hydro - Flexible run-of-river	10.5	9	20	81.2%	42.4%
Mahinerangi Wind	Wind	36	9	51	25.0%	32.6%
Manapouri	Controlled Hydro	800	784	2685	98.0%	71.0%
Ohau A	Controlled Hydro	264	See Waitaki scheme			
Ohau B	Controlled Hydro	212	See Waitaki scheme			
Ohau C	Controlled Hydro	212	See Waitaki scheme			
Paerau/Patearoa	Hydro - Inflexible run-of-river	12.25	9	27	72.0%	50.3%
Roxburgh	Controlled Hydro	320	See Clutha scheme			
Tekapo A	Controlled Hydro	30	See Tekapo scheme			
Tekapo B	Controlled Hydro	154	See Tekapo scheme			
Waipori	Hydro - Flexible run-of-river	83.6	68	87	81.2%	23.8%
Waitaki	Controlled Hydro	105	See Waitaki scheme			
Whitehill	Wind	58	15	85	25.0%	33.5%

* Energy and capacity contributions of this plant are detailed in the aggregated hydro schemes shown in Table 8.

Table 8: Existing New Zealand controllable hydro supply

Scheme	Island	MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)	Winter Capacity Rating	Winter Energy Rating
Waikato	NI	1,070	990	2,350	98%	50.1%
Waikaremoana	NI	139	136	267	98%	43.8%
Tekapo	SI	184	180	2,779	98%	36.5%
Waitaki	SI	1,553	1,522		98%	
Clutha	SI	752	737	1,417	98%	50.9%
Start storage	NI	n/a	n/a	350	n/a	n/a
Start storage	SI	n/a	n/a	2,400	n/a	n/a

4.2 New Generation

Figures 84 and 85 show the expected capacity and energy contributions from new generation in aggregate form. Each graph shows contributions by the generator type, and in which island the generation is based. Future solar generation includes growth forecast in the medium demand forecast.

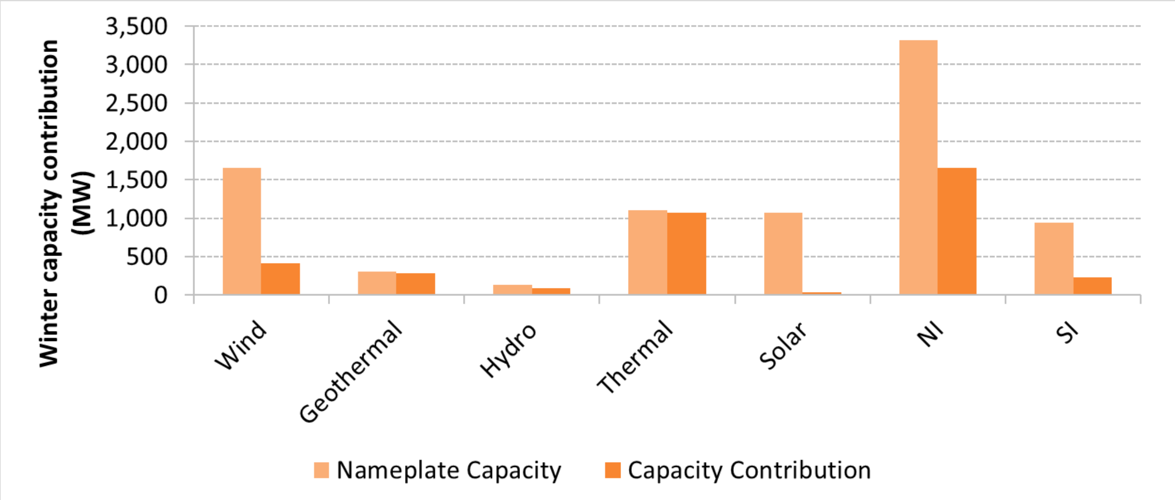

Figure 96: Winter Capacity Contribution from New Generation (Medium Demand Scenario)

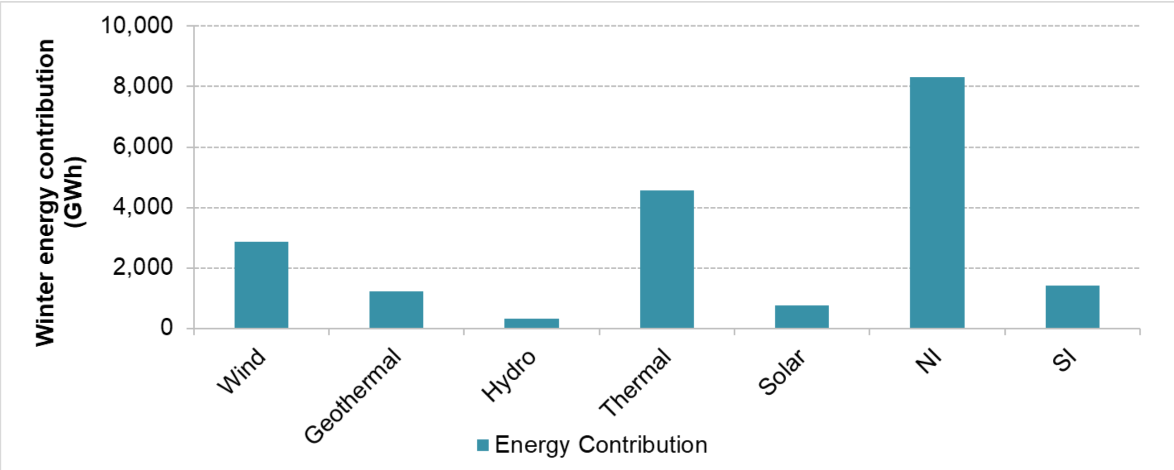

Figure 97: Winter Energy Contribution from New Generation (Medium Demand Scenario)

The expected capacity contribution from future generation has increased from 1,669 MW in our 2019 analysis to 1,884 MW in 2020. This is due to a substantial increase in future thermal generation. There has, though, been a small drop in future wind and geothermal generation. While the medium demand forecast projects a large increase in future solar generation, this does not contribute significantly to meeting winter peak demand.

There has been a corresponding increase in total winter energy contribution from 9,113 GWh in 2019 to 9,740 GWh in 2020.

The following tables summarise new generation used in the assessment. The dates at which new generation becomes available is based on the type of generation, and its consent status.

Table 9: New generation aggregated by type

Type	Nameplate MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)
Wind	1,650	413	2,876
Geothermal	306	281	1,231
Hydro	128	93	325
Thermal	1,100	1,067	4,558
Solar (large scale)	47	2	33

Table 10: Solar generation per island per year (medium solar)[23]

Year	NI Solar and Battery Contribution to WEMs (GWh)	NI Solar and Battery Capacity Contribution to WCM (MW)	SI Solar and Battery Contribution to WEMs (GWh)	SI Solar and Battery Capacity Contribution to WCM (MW)
2020	49.5	8.3	23.7	6.1
2021	64.1	11.2	30.8	7.8
2022	89.5	17.1	43.2	11.1
2023	123.0	24.2	59.6	15.3
2024	166.9	30.8	80.3	19.0
2025	228.3	39.4	109.4	24.2
2026	312.7	46.6	148.5	28.0
2027	407.9	56.4	192.8	33.7
2028	500.7	64.7	233.9	39.5
2029	577.3	78.9	268.9	47.4

Table 11: New generation aggregated by island (Medium Demand Scenario)

Island	Nameplate MW	Assumed Contribution to Capacity Margins (MW)	Assumed Contribution to Energy Margins (potential GWh over April - Sep)
NI	2,610 + 706 of distributed solar	1,651	8,327
SI	621 + 319 of distributed solar	233	1,413

[23] See Appendix 6:Detailed Demand Forecast Assumptions for other scenarios

4.2.1 New Generation Commissioning Dates

The dates at which new generation becomes available is based on the type of generation, and its consent status. The table below shows the earliest commissioning dates for different types of generation and consent status. These commissioning dates are used for all sources of new generation.

Table 12: New generation commissioning dates based on consent status and generation type

	Consented and proceeding	Consented and on hold/awaiting market conditions to change	Consented and on hold, revision or reconsent required	Not consented and on hold, but consent likely sought within 2 years
Thermal	Estimated build date	2022	2023	2025
Geothermal	Estimated build date	2023	2024	2026
Wind	Estimated build date	2023	2024	2026
Hydro	Estimated build date	2024	2025	2027
Solar (large scale)	Estimated build date	2022	2023	2025

We have explicitly not accounted transmission build times into these commissioning dates, as transmission builds vary from project to project.

4.3 Other Generation Assumptions

4.3.1 Other Generation De-Ratings Applied

The following de-ratings are applied to generation:

- In the assessment of the New Zealand WEM and South Island WEM, thermal generation has been reduced by 92 GWh in the North Island to reflect spinning reserve and frequency keeping requirements.[24]
- In the assessment of the North Island WCM, to account for limited short-term storage availability, these generators are not treated as run-of-river hydro:
  - Matahina de-rated by 13 MW
  - Patea de-rated by 5 MW
  - Tokaanu de-rated by 20 MW.
- The Waikato hydro scheme is de-rated by 60 MW to account for the impact of chronological flow constraints in the derivation of the North Island WCM.

[24] This is different than that suggested in the SSAD. This difference is due to various technological and regulatory changes over recent years; lower quantities of ancillary services are required compared to when the SSAD was published. The Electricity Authority has provided us with analysis of 2012 and 2013 dry spells that estimates the reduction in thermal generation due to spinning reserves and frequency keeping at 92 GWh. The SSAD states a value of 303 GWh, if this value was used instead of 92 GWh, the New Zealand Winter Energy Margins would increase by approximately 0.8-0.9%, and the South Island Energy Margins would increase by 2.3% (assuming HVDC is not constrained in the margin calculation).

4.3.2 Fuel or Operational Limits

With the exception of Whirinaki, it is assumed thermal fuel availability, or operational limitations, do not limit thermal generation in this medium-term assessment.

To reflect on-site fuel storage and delivery limitations, Whirinaki's energy contribution is limited to 30 GWh per winter in the derivation of the WEMs.

4.3.3 Average Hydro Storage

The winter start storage for assessing WEMs are those specified in the SSAD. The start storage levels are:

- 2,750 GWh for New Zealand.
- 2,400 GWh for the South Island.

4.3.4 Run-of-River Hydro, Cogeneration, Geothermal, Wind and Solar Capacity Contribution

The capacity contributions of run-of-river hydro, cogeneration and geothermal generation assumed for the North Island WCM are determined from historical generation at peak periods.

Generation output for the 500 trading periods with highest demand is collected. This is then analysed to determine the average contribution of run-of-river hydro, cogeneration and geothermal during peak periods. Flexible run-of-river hydro is assumed to contribute 81.2 per cent of maximum nameplate capacity, inflexible run-of-river hydro is assumed to contribute 72.0 per cent of capacity, geothermal is assumed to contribute 91.7 per cent of capacity and cogeneration is assumed to contribute 61.0 per cent of capacity.

For wind generation, this assessment assumes a wind capacity contribution of 25 per cent as defined in the SSAD.

For large scale solar generation, this assessment assumes a solar capacity contribution of 5 per cent. This will be further refined as actual operational data is obtained.

Appendix 5: TRANSMISSION

Inter-island transmission assumptions are required for assessment of the South Island WEM and the North Island WCM. North Island energy supply can meet some South Island energy demand in the assessment of the South Island WEM. Similarly, South Island capacity can meet some North Island demand in the assessment of the North Island WCM.

It is assumed that the HVDC capability will be the combined capability of Pole 2 and Pole 3 for all scenarios.

5.1 HVDC FLOW SOUTH CONTRIBUTES TO SOUTH ISLAND WEM

It is assumed that the North Island will be able to supply the South Island with 2,101 GWh (480 MW average transfer[25]) of energy during the winter period. This energy transfer is dependent on the North Island having the required surplus energy available. To allow for this restriction the lesser value of 2,101 GWh or the net North Island energy surplus, which is determined in the same way as the South Island WEM, is used.

5.2 HVDC FLOW NORTH CONTRIBUTES TO WCM

It is assumed during winter the South Island has the potential to supply the North Island with capacity.

The contribution of South Island capacity to North Island demand is a function of surplus capacity available in the South Island, depicted in Figure 86. The contribution is determined in the same way as the North Island WCM. The function used in this process was derived using simulation analysis, taking account of:

- HVDC capacity
- transmission losses
- North Island instantaneous reserve requirements
- the low probability of forced outages on the HVDC link.

This assessment assumes that both Pole 2 and Pole 3 are always available in the four key scenarios.

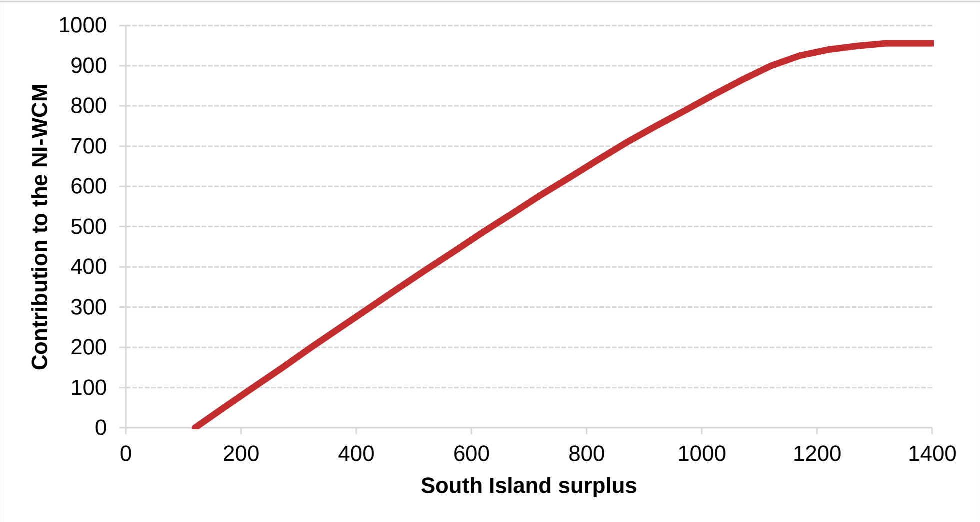

Figure 98: Relationship between South Island surplus and its contribution to the North Island WCM

[25] As discussed in the System Security Forecast, on occasion the HVDC southward limit will be restricted to 260 MW due to low wind generation in the Wellington region, however at times south transfer is also expected to reach 650 MW.

5.3 AC Transmission Assumptions

This assessment does not explicitly model AC transmission constraints. The implicit assumption is that AC constraints will not reduce inter-island transfers below the limits specified above.

Appendix 6: DETAILED DEMAND FORECAST ASSUMPTIONS

The demand forecasts used in this assessment are based on a forecast prepared by Transpower and align with Transpower's "Whakamana i Te Mauri Hiko" work.

6.1 DEMAND FORECAST METHODOLOGY

Future electricity demand is a critical factor to consider when assessing security of supply. For this assessment we prepare both winter peak demand forecasts (for the WCM) and winter energy demand forecasts (for the WEMs) for each scenario. For this year's assessment, forecasts are aligned with Transpower's "Whakamana i Te Mauri Hiko" work.

We use an ensemble approach when preparing our demand forecasts. A base ensemble demand forecast (the 'base forecast') is derived from a combination of:

- Traditional econometric forecast
- Long term linear regression
- Short term linear regression
- MBIE Energy Demand and Generation Scenarios.

Electricity market reconciliation data (up to 2019 for the final report and, up to 2018 for the draft report) is a primary forecasting input. The base forecast is derived on a 'gross basis', it includes demand served from the grid and from embedded generation. The base forecast is calculated for each grid exit point (GXP) and on a half hourly basis.

Demand forecasts, used for each scenario, start with a base forecast. This forecast is then adjusted to account for any known step changes or future deviations from what has been historically observed. For example, the demand forecasts used for the Medium Demand and High Demand scenario are adjusted to take account of varying levels of electrification of process heat and transport.

Winter energy demand is calculated by summing base forecast demand, over each GXP in both islands, and over each winter half hour period. Winter peak demand is calculated by averaging base forecast demand, over each island, and over the highest 200 half hours of winter daytime demand.

Transmission losses are calculated by determining GXP offtake quantities and applying a static loss factor. These losses are added to each winter peak and energy demand to provide the minimum about of generation required for that forecast.

The flow chart below shows how both the underlying peak and energy forecasts are determined.

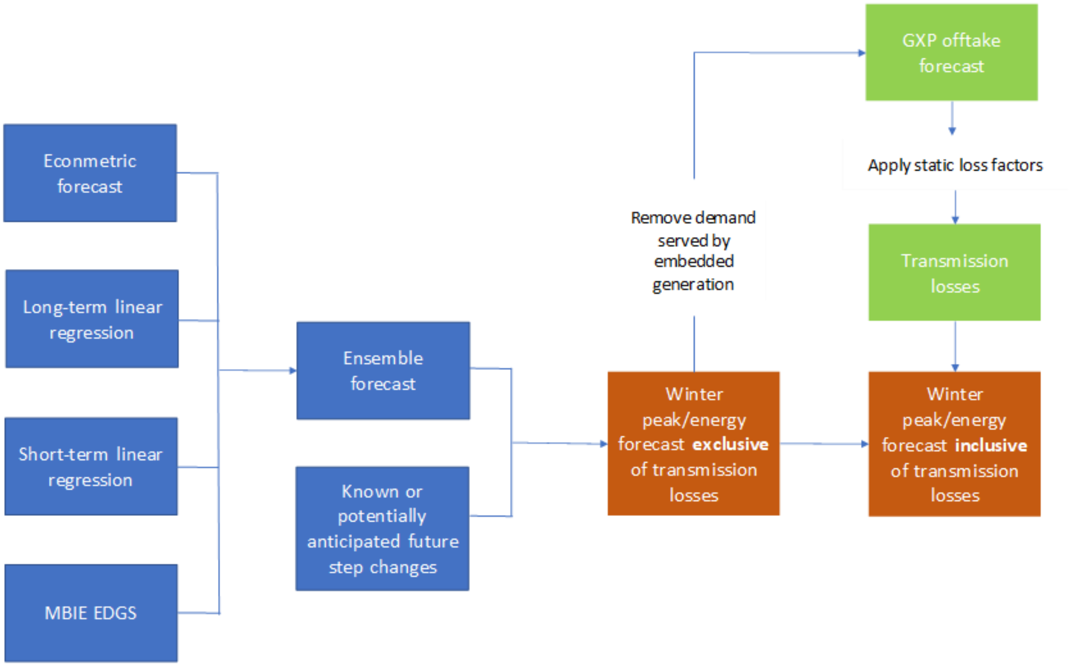

Figure 99: Schematic of how demand forecast is prepared

6.1.1 Demand Response

Winter energy demand forecasts have been reduced by 2 per cent to allow for voluntary demand response.

Winter peak demand forecasts in the North Island have been reduced by 176 MW to account for demand response at peak times.

These reductions include voluntary demand response resulting from high spot prices or retailer pricing initiatives. Reductions in demand as a result of savings campaigns or forced rationing are, though, excluded.

6.1.2 Transmission Losses (for WEMs)

In the calculation of the WEMs static loss factors have been applied, as defined in the SSAD. These are:

- 3.5 per cent losses for New Zealand for the purposes of the NZ-WEM.
- 4.5 per cent losses for the South Island for the purposes of the SI-WEM.

6.2 Demand Data used for the 2020 Annual Assessment

Demand forecast for each scenario are shown in the charts below. They exclude transmission losses and demand response. To allow comparisons with other forecasts energy demand is shown on a yearly (rather than winter basis).

Detailed demand forecast data used for the assessment are also provided in the tables below.

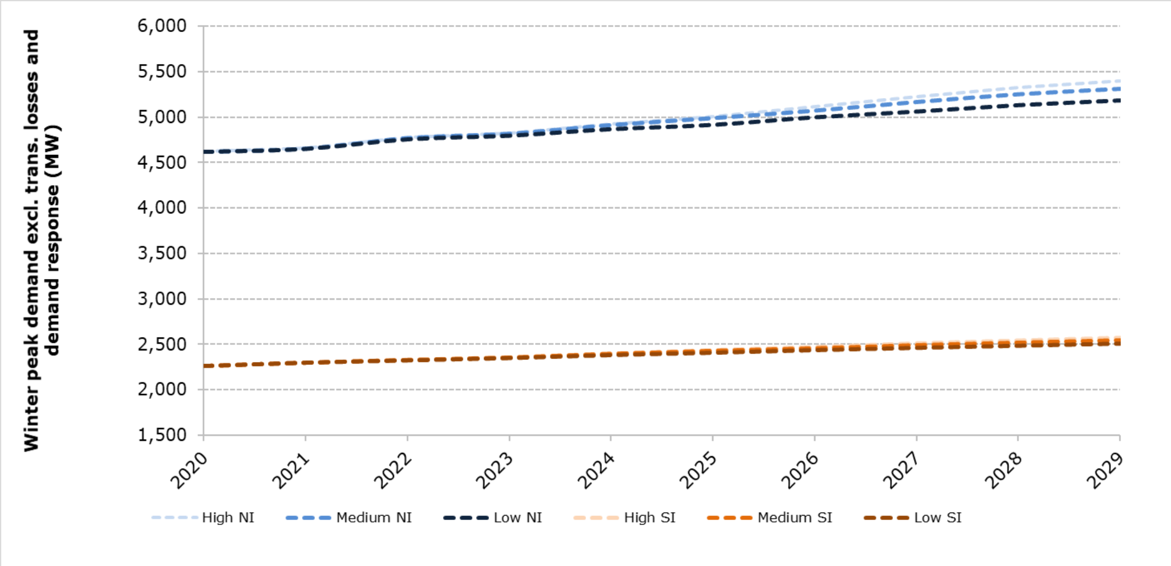

Figure 100: Winter peak demand excluding transmission losses and demand response

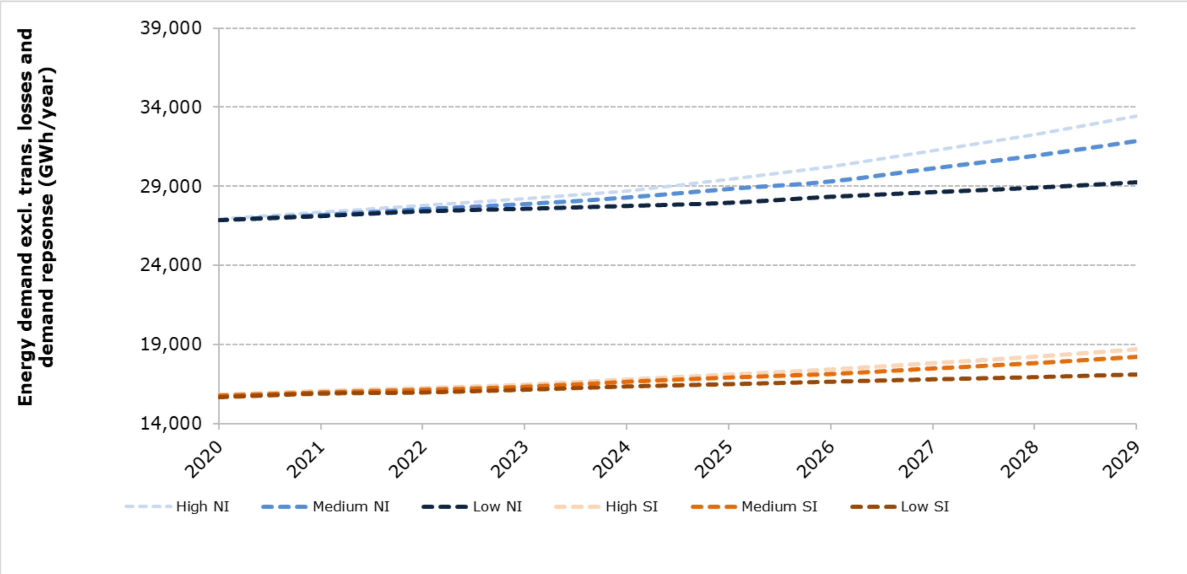

Figure 101: Annual energy demand, excluding transmission demand response and demand response

6.2.1 Low Demand Forecast

Table 13: Winter South Island energy demand forecast

Calendar Year	South Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	7180	21	291	323	8200
2021	7298	27	291	328	8329
2022	7305	35	291	329	8344
2023	7376	44	291	332	8428
2024	7466	56	291	336	8534
2025	7509	70	291	338	8593
2026	7555	86	291	340	8657
2027	7603	107	291	342	8728

Calendar Year	South Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2028	7644	124	291	344	8787
2029	7700	142	291	346	8865

Table 14: Winter North Island energy demand forecast

Calendar Year	North Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	11839	45	331	343	14537
2021	11906	56	331	344	14617
2022	12069	73	331	349	14802
2023	12093	93	331	349	14846
2024	12180	117	331	352	14960
2025	12229	148	331	353	15041
2026	12382	184	331	358	15235
2027	12474	229	331	361	15374
2028	12576	268	331	364	15518
2029	12694	308	331	367	15681

Table 15: Winter South Island peak (H100) demand forecast

Calendar Year	South Island Peak (H00) Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	2130	5	67	104	2364
2021	2166	7	67	106	2402
2022	2186	9	68	107	2428
2023	2209	12	68	108	2455
2024	2239	15	68	109	2489
2025	2260	18	68	110	2516
2026	2286	21	68	112	2545
2027	2306	26	68	113	2571
2028	2324	29	68	113	2595
2029	2342	34	68	114	2619

Table 16: Winter North Island peak (H100) demand forecast

Calendar Year	North Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	4089	7	78	118	4736
2021	4120	9	78	119	4770
2022	4220	14	78	122	4879
2023	4256	19	78	123	4920
2024	4323	23	78	124	4995
2025	4362	30	78	126	5043
2026	4442	34	78	128	5129
2027	4497	41	79	130	5194
2028	4560	48	79	131	5267
2029	4602	58	79	133	5320

6.2.2 Medium Demand Forecast

Table 17: Winter South Island energy demand forecast

Calendar Year	South Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	7244	24	291	326	8270
2021	7338	31	291	330	8375
2022	7392	43	291	333	8444
2023	7458	60	291	336	8529
2024	7595	80	291	342	8694
2025	7679	109	291	346	8810
2026	7739	149	291	348	8912
2027	7855	193	291	353	9078
2028	7970	234	291	359	9239
2029	8123	269	291	366	9433

Table 18: Winter North Island energy demand forecast

Calendar Year	North Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	11819	50	331	341	14520
2021	11926	64	331	344	14645
2022	12113	89	331	350	14863
2023	12208	123	331	353	14995
2024	12393	167	331	358	15229
2025	12581	228	331	364	15484
2026	12741	313	331	369	15733
2027	13043	408	331	378	16140
2028	13348	501	331	387	16547
2029	13725	577	331	399	17012

Table 19: Winter South Island peak (H100) demand forecast

Calendar Year	South Island Peak (H00) Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	2131	6	67	104	2365
2021	2166	8	67	106	2404
2022	2191	11	68	107	2435
2023	2214	15	67	108	2463
2024	2251	19	68	110	2506
2025	2278	24	68	111	2541
2026	2302	28	68	112	2569
2027	2330	34	68	114	2606
2028	2352	39	68	115	2635
2029	2370	47	68	116	2662

Table 20: Winter North Island peak (H100) demand forecast

Calendar Year	North Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	4089	8	78	118	4737
2021	4121	11	78	119	4774
2022	4231	17	78	122	4894
2023	4273	24	78	123	4943
2024	4360	31	78	126	5041
2025	4424	39	79	127	5119
2026	4498	47	79	130	5203
2027	4582	56	79	132	5301
2028	4659	65	79	134	5388
2029	4703	79	80	135	5449

6.2.3 High Demand Forecast

Table 21: Winter South Island energy demand forecast

Calendar Year	South Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	7259	25	291	327	8287
2021	7374	34	291	332	8416
2022	7438	50	291	335	8498
2023	7512	71	291	338	8598
2024	7651	101	291	344	8773
2025	7745	143	291	349	8913
2026	7830	205	291	352	9063
2027	7952	271	291	358	9257
2028	8079	335	291	364	9454
2029	8258	384	291	372	9690

Table 22: Winter North Island energy demand forecast

Calendar Year	North Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	11869	53	331	343	14576
2021	12019	70	331	347	14747
2022	12257	103	331	355	15025
2023	12387	148	331	358	15205
2024	12612	209	331	365	15497
2025	12857	299	331	373	15839
2026	13142	430	331	382	16265
2027	13486	573	331	392	16763
2028	13862	717	331	404	17295
2029	14323	826	331	419	17878

Table 23: Winter South Island peak (H100) demand forecast

Calendar Year	South Island Peak (H00) Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	2131	6	67	104	2366
2021	2167	8	67	106	2405
2022	2191	12	67	107	2435
2023	2214	16	68	108	2464
2024	2250	20	68	110	2507
2025	2280	25	68	111	2545
2026	2311	30	68	113	2582
2027	2343	37	68	114	2623
2028	2369	40	68	116	2654

Calendar Year	South Island Peak (H00) Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2029	2392	48	68	117	2686

Table 24: Winter North Island peak (H100) demand forecast

Calendar Year	North Island Demand (GWh)				
	GXP offtake	Solar and battery contribution	Non-modelled embedded generation contribution	Transmission losses	Demand excl. demand response
2020	4090	9	78	118	4739
2021	4123	12	78	119	4776
2022	4234	18	78	122	4897
2023	4276	26	78	123	4948
2024	4363	32	78	126	5048
2025	4437	42	79	128	5134
2026	4539	47	79	131	5245
2027	4633	57	80	133	5355
2028	4728	68	79	136	5464
2029	4788	82	80	138	5540