Meeting Date: 26 October 2022

2022 ANNUAL SECURITY OF SUPPLY ASSESSMENT

SECURITY AND RELIABILITY COUNCIL

The 2022 annual Security of Supply Assessment, 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 2022 annual Security of Supply Assessment

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. The 2022 SOSA provides a medium-term view of the balance between supply and demand in the New Zealand electricity system between 2022-2031.

1.3. The SRC is asked to consider the 2022 SOSA, so it can provide meaningful feedback to the system operator. The SOSA is attached as Appendix A (SRC summary paper) and Appendix B (full paper)). The secretariat notes that SRC members do not need to read the entire SOSA and offers the following guidance:

a) The SRC summary paper provides a useful overview of the key findings and areas of concern

b) Section one (the Executive Summary in the full report) is essential reading

c) Section five is very relevant to the SRC, as it shows a broader range of results (with sensitivities) than the Executive Summary and includes a comparison with last year's assessment

d) Sections two and three may be useful for readers unfamiliar with SOSA reports, covering background and a summary of the methodology

e) Section four is detailed-oriented and should only be used by SRC members seeking to understand the mechanics of the methodology and underlying assumptions.

1.4. The system operator will attend the SRC meeting to answer any questions about the 2022 SOSA.

The SOSA framework

1.5. The security standards set by the Authority are:

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

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

c) 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).

1.6. The margins 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 oversupply that minimises overall cost to the country.

1.7. 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.

1.8. 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.

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

1.10. 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.

1.11. Demand forecasts were updated again 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

1.12. The SRC will be updated on the 2023 SOSA at its Q4 2023 meeting, date TBC.

Change in approach for 2022 SOSA

1.13. In previous years the system operator has used four core scenarios for SOSA (low demand, medium demand, high demand, and gas constrained). Under that approach each scenario had a different 'underlying' demand growth rate (for winter only) and a different rate of uptake of electrification and distributed energy resource technologies.

1.14. For 2022 SOSA the system operator has used a single reference scenario (reference case) that represents the resources potentially available to the power system over the 10-year assessment horizon. The assumptions and inputs for the reference case are based upon:

a) a market participant survey;

b) Transpower's demand forecast aligned with transmission and strategic planning

c) The Authority's Security Standards Assumptions Document (SSAD)[3]

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[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
[3] Security Standards Assumption Document

d) Industry and MBIE gas information

e) Historical market behaviour and other available market information.

1.15. The system operator consulted on the change in approach and has published the submissions and the system operator's response.[4] If members have concerns about, or additional feedback for the system operator on, the approach and assumptions, they may wish to raise these with the system operator at the October meeting, so they can be considered for future SOSA's.

Assumptions

1.16. Key assumptions in the reference case:

a) Existing generation and industrial demand will not change unless decommissioning is publicly announced, and decommissioning activities are actively being pursued

b) A medium demand forecast

c) Tiwai remains

d) "Significant" amounts of thermal generation are not decommissioned in the near term

e) Investment in upstream gas sector continues

f) The HVDC interconnector is not upgraded

1.17. Generation is divided into the following categories:

- Stage 1 - existing and committed
- Stage 2 - consented, on hold
- Stage 3 - consented, on hold, requiring reconsent
- Stage 4 - not consented, but consent could be sought soon.

1.18. The system operator has confirmed its intention to retain the webtool as a way for the public to combine sensitivities and form their own views on the10-year outlook of security of supply. Members may wish to enquire whether this will be available and, if so, in what form.

Sensitivities

1.19. Sensitivities may also be applied to each scenario to reflect uncertain changes in supply and demand and represent what the system operator considers as plausible variations from the reference case.

1.20. The range of sensitivities apply to either the demand or supply side, for example decommissioning the Taranaki Combined Cycle generation plant (TCC) and delayed build times for new generation (supply side) and demand growth and changes in peak demand (demand side).

1.21. Because of the large number of potential combinations of scenarios, the report only considers a subset in detail.

[4] 2022 SOSA consultation feedback and system operator response

1.22. **Greater demand response sensitivity:** The system operator planned to include an additional 'greater demand response' sensitivity based on information from distributors but did not receive a sufficient response to be able to generate a sensitivity.

1.23. **NZ Battery** is not included as a sensitivity, again due to a lack of available information. However, section 6 provides a useful overview of the system operator's views on maintaining security margins with greater renewable generation, including an assessment of the NZ Battery Project's potential contribution, with links to additional information.

2. The key findings of the 2022 SOSA

2.1. As noted in the overview (p6), **both the demand forecast, and the supply pipeline have increased** compared to 2021 SOSA based on distributor projections and a "significant" increase in the number of renewable supply projects. These have potential to bring forward or push back when the reference case falls below the security standards.

2.2. **The majority of new renewable generation sources are intermittent** (wind and solar) and the report notes (p6) *"intermittent generation has a larger impact on the energy margin than the capacity margin and is a key driver of the capacity margin falling below the security standard earlier than the energy margin."*

2.3. The implication of this is, as noted in the report (p6) "***existing and consented generation, including thermal generation and its fuel supply, is required to maintain capacity security and energy margins above the security standards up to 2028.***" This is of key relevance to the SRC's advice, given the government's 2030 decarbonisation aspirations.

2.4. *"**The pipeline of renewable projects is sufficient to reach the Government's 100% renewable electricity aspiration."*** Importantly, as also noted in the report (p6) *"This would require a significant step change in the rates of project consenting and construction."*

2.5. ***"The reference case falls below the NZ-WEM security standard by 2028"*** based on existing and committed new projects but could fall below as early as 2024, or beyond the 10-year horizon, when the full range of sensitivity combinations are applied.

2.6. ***"The refence case falls below the NI-WCM security standard by 2025****"* based on existing and committed new projects but could fall below as early as 2023, or beyond the 10-year horizon, when the full range of sensitivity combinations are applied.

2.7. ***"The refence case stays above the SI-WEM security standard for the 10-year horizon"*** but could fall below as early as 2025, when the full range of sensitivity combinations are applied.

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 2022 SOSA results?

Q2. What comment or feedback does the SRC have for the system operator on its approach to, or findings of, the 2022 SOSA?

Q3. What further information, if any, does the SRC wish to have provided to it by the secretariat?

Q4. What advice, if any, does the SRC wish to provide to the Authority?

4. Appendices

4.1. Appendix A: System operator's summary paper for the SRC

4.2. Appendix B: 2022 annual Security of Supply Assessment (SOSA)

Appendix A: System operator's summary paper for the SRC

Appendix B: 2022 annual Security of Supply Assessment

TRANSPOWER

Security and Reliability Council Paper

Meeting date:	03 October 2022
Author:	Ramu Naidoo Principal Market Advisor, Market & Business

Security of Supply Assessment 2022

1 Purpose

The purpose of this paper is to summarise the purpose for the annual security of supply assessment (SOSA) and the process followed for the 2022 SOSA to analyse energy and capacity margins. This analysis is provided as guideline to market participants who can then decide if or when they will offer their generation into the market.

To avoid duplication, the reader is referred to the executive summary of the 2022 SOSA final report[1] which has a comprehensive summary of the assessment approach and results.

2 What we measure in the SOSA and why

The 2022 SOSA provides a ten-year view (2022 to 2031) of security of supply for different supply and demand scenarios. The purpose is to enable industry stakeholders to compare the risk of supply shortages both between scenarios and over time to inform risk management and investment decisions. Transpower is Code-obligated to produce the assessment, and many of the assumptions used are prescribed by the Electricity Authority.

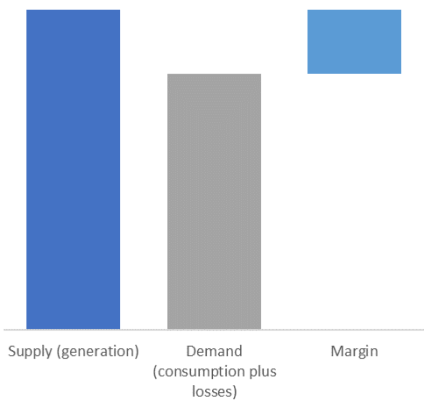

Figure 1: Margin visualisation

The assessment is essentially a long-term view of the balance between supply and demand in the New Zealand electricity system. We present this information using three margins, all of which represent the difference between supply and demand. Generally, an excess of supply (i.e. generation) is maintained in order to ensure that demand can always be met – this excess is referred to as the margin (Figure 1).

The three margins presented in the assessment cover the key areas of risk for the electricity system and include the New Zealand and South Island winter energy margins, and North Island winter

[1] This can be found here: https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/2022%20SOSA%20-%20Final%20Report%20-%20Final%20Version.pdf

capacity margin. 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 North Island winter capacity margin assesses whether it is likely there will be adequate generation and HVDC transmission capacity to meet peak North Island demand over winter.

The margins are then compared against what is known as the security of supply standards. The standards represent the Electricity Authority's view of an efficient level of electricity generation investment. For example, if the margins are below the standards, this implies that investment in new generation would be an economically rational exercise according to the Authority's winter margin assessment. It can also be interpreted as representing the likelihood of electricity shortage – the higher the margin the less likely electricity shortage will be.

3 2022 SOSA consultation and final report

We published the 2022 SOSA draft report on 18 May 2022. We received two submissions on the draft. The final report together with a summary of submissions and our responses was published on 30 June 2022[2].

[2] The System Operator's final 2022 Security of Supply Annual Assessment: https://www.transpower.co.nz/system-operator/security-supply-and-ercs/policies-plans-and-publications

TRANSPOWER

Security of Supply Assessment 2022

System Operator

Version: 2.0

Date: 30 June 2022

Version	Date	Change
1.0	18 May 2022	First release
2.0	30 June 2022	Final release

IMPORTANT

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1.0 Executive Summary

Introduction

Overview

The demand forecast has increased compared to the 2021 SOSA, largely due to information provided by the distributors in preparing this year's demand forecast on expected increases on their networks.

The supply pipeline has increased compared to the 2021 SOSA, largely due to a significant increase in the number of renewable supply projects that are currently unconsented but are expected to seek consents within the next two years. The estimated commissioning dates for most of the unconsented supply projects are between 2028 and 2031.

The SOSA analysis considers three security of supply margins against security standards set by the Electricity Authority:

> **New Zealand winter energy margin:** the reference case (which represents the resources available to the market) falls below the security standard by 2028 when considering only those new supply projects which are existing and committed – including consented and unconsented projects shows the margin staying above the security standards for the 10-year horizon. Key sensitivities that impact this margin include but are not limited to high demand growth, a potential Tiwai exit and low gas supply. The full range of sensitivity combinations showed that the margins could fall below the security standard as early as 2024 or delay the crossing until beyond the 10-year horizon.
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> **North Island winter capacity margin**: the reference case falls below the security standard by 2025 when considering only those new supply projects which are existing and committed – including consented and unconsented projects delay this date until 2028. Key sensitivities that impact this margin include but are not limited to thermal decommissioning, low gas supply and step changes in demand. The full range of sensitivity combinations showed that the margins could fall below the security standard as early as 2023 or as delay the crossing until beyond the 10-year horizon.
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> **South Island winter energy margin:** the reference case stays above the security standard for the 10-year horizon. When combining multiple sensitivities and conservative estimates of new supply projects, the margin can fall below the security standard as early as 2025.

The majority of the unconsented supply pipeline is made up of intermittent generation sources (wind and solar). Intermittent generation has a larger impact on the energy margin than the capacity margin and is a key driver of the capacity margin falling below the security standard earlier than the energy margin.

Existing and consented generation, including thermal generation and its fuel supply, is required to maintain capacity and energy margins above the security standards up to 2028.

The pipeline of renewable projects is sufficient to reach the Government's 100% renewable electricity aspiration (including those expecting consent in the next two years). They could contribute 22,300 GWh of winter energy and around 3,100MW of winter capacity. This would require a significant step change in the rates of project consenting and construction.

Transpower, as the system operator, is responsible for publishing the medium-term security of supply assessment (SOSA) annually. This assessment provides a 10-year assessment (2022 to 2031) of the balance between supply and demand in the New Zealand electricity system.

Three security of supply margins are evaluated, the:

a) New Zealand Winter Energy Margin (NZ-WEM);

b) South Island Winter Energy Margin (SI-WEM); and

c) North Island Winter Capacity Margin (NI-WCM).

The energy margins assess the adequacy of generation and HVDC transmission capacity to meet expected electricity demand across the winter months under different supply and demand conditions. The capacity margin assesses the adequacy of generation and HVDC transmission capacity to meet peak winter North Island demand under different supply and demand conditions.

These margins are compared against security standards set by the Electricity Authority in the Security Standards Assumptions Document (SSAD)[1].

Reference Scenario (Case)

We have used a single reference scenario (reference case) for the future New Zealand electricity system that represents the resources potentially available to the power system over the 10-year assessment horizon. The reference case represents what the market could develop, not necessarily what it will develop[2]. In making this representation, a fixed set of assumptions are used, and these are then adjusted using several key variables, or sensitivities, to test a range of plausible deviations from the reference case. This is a change in approach from previous years where we have used four central scenarios. The change was generally supported during consultation with industry earlier this year.

In the reference case we assume existing generation and industrial demand will not change unless decommissioning is publicly announced, and decommissioning activities are actively being pursued.

The reference case assumes a medium demand forecast and that during the 10-year assessment horizon the NZAS aluminium smelter at Tiwai Point ('Tiwai') remains active, the Taranaki Combined Cycle (TCC) generator is not decommissioned, investment in the upstream gas sector continues, and the HVDC interconnector will not be upgraded.

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[1] Electricity Authority, Security Standards Assumptions Document.

[2] The assumptions and inputs for the reference case are based upon a market participant survey, Transpower's demand forecast aligned with transmission and strategic planning (e.g. Whakamana i Te Mauri Hiko), the Electricity Authority's Security Standards Assumptions Document, industry and MBIE gas information, historical market behaviour, and other available market information.

Sensitivities

We have identified several key variables that we explore as sensitivities in our analysis. These sensitivities represent plausible variations from the reference case that could occur over the 10-year assessment horizon.

In addition to applying individual sensitivities to the reference case, we consider applying all valid sensitivity combinations to the reference case to form a wider range of plausible futures. Both the reference case and the sensitivities (and their feasible combinations) are assessed for different potential future generation[3] scenarios which we refer to in the SOSA as supply pipeline stages[4].

These sensitivities are:

1. *Thermal decommissioning:* this sensitivity tests the potential impact of the near-term decommissioning of one significant fossil-fuelled thermal generation asset. The example being utilised in this assessment is the potential 2023 decommissioning of the Taranaki Combined Cycle (TCC) generator.
2. *Dry year reserve:* This sensitivity tests the impact if 480MW of existing fossil-fuelled thermal capacity had limited operation and could only be used during periods of low hydrology, but not for short term, unanticipated supply shortages unrelated to low hydrology. Therefore, this capacity contributes to the energy margins, but not the capacity margin.
3. *Low gas supply:* This sensitivity is intended to show a constrained case for domestic gas production over the coming decade as well as limited gas demand response from industrial gas users to enable increased electricity generation[5].
4. *Delayed build times*: This sensitivity delays commissioning dates for all new generation by one year.
5. *Accelerated upgrade of the HVDC:* This sensitivity uses the Net Zero Grid Pathways (NZGP) scenario which shows the earliest this could occur is 2027[6].
6. *No new thermal development:* This sensitivity considers the impact if no new fossil-fuelled thermal generation is developed. While we did not consult on this sensitivity, it was included in the 2021 SOSA and we considered it useful to also include this year.
7. *Demand growth:* This sensitivity considers higher and lower rates of electricity demand growth compared with the reference case (which uses the medium demand

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[3] This also includes batteries.
[4] Different supply pipeline stages are discussed further below.
[5] This sensitivity is based on the low gas supply sensitivity assessed in the 2021 SOSA but also considers the potential for limited gas demand response from industrial gas users as outlined in the 2022 Security of Supply Forecast and Information Policy (SOSFIP) consultation undertaken by the system operator.
[6] See page 40 of the Net Zero Grid Pathways document Transpower NZGP Scenarios Update_Dec2021.

forecast). Each of these differ by varying the rates of acceleration of electrification across the economy as well as the growth of distributed energy resources.

8. *Tiwai exits:* This sensitivity assumes that Tiwai exits the New Zealand market when its current electricity supply contract expires at the end of 2024.
9. *Step change increase in demand:* This sensitivity explores the potential of an additional step change in demand for each island from new industrial sources of demand such as data centres, other new industries, or electrification of process heat.
10. *Change in peak transmission pricing:* This sensitivity considers the potential peak demand increases as the electricity sector adjusts to a change in transmission pricing methodology.

We planned to include a *greater demand response* sensitivity to explore the impact of increased uptake in demand response in both the North and South Islands. We sought additional information from electricity distribution businesses (EDBs) and industrial users on expectations of demand response but did not receive a sufficient response to be able to generate a sensitivity.

The 2021 SOSA considered the government's aspirational target of 100% renewable energy by 2030 as a separate case study. We repeat this assessment this year in Section 6.0.

The *NZ battery* assessment was not included as a separate sensitivity due to insufficient information being available but is considered as part of our 100% renewable energy case study in Section 6.0. More details on the NZ battery project can be found on the Ministry of Business, Innovation, and Employment website.[7]

Demand and supply assumptions

Demand

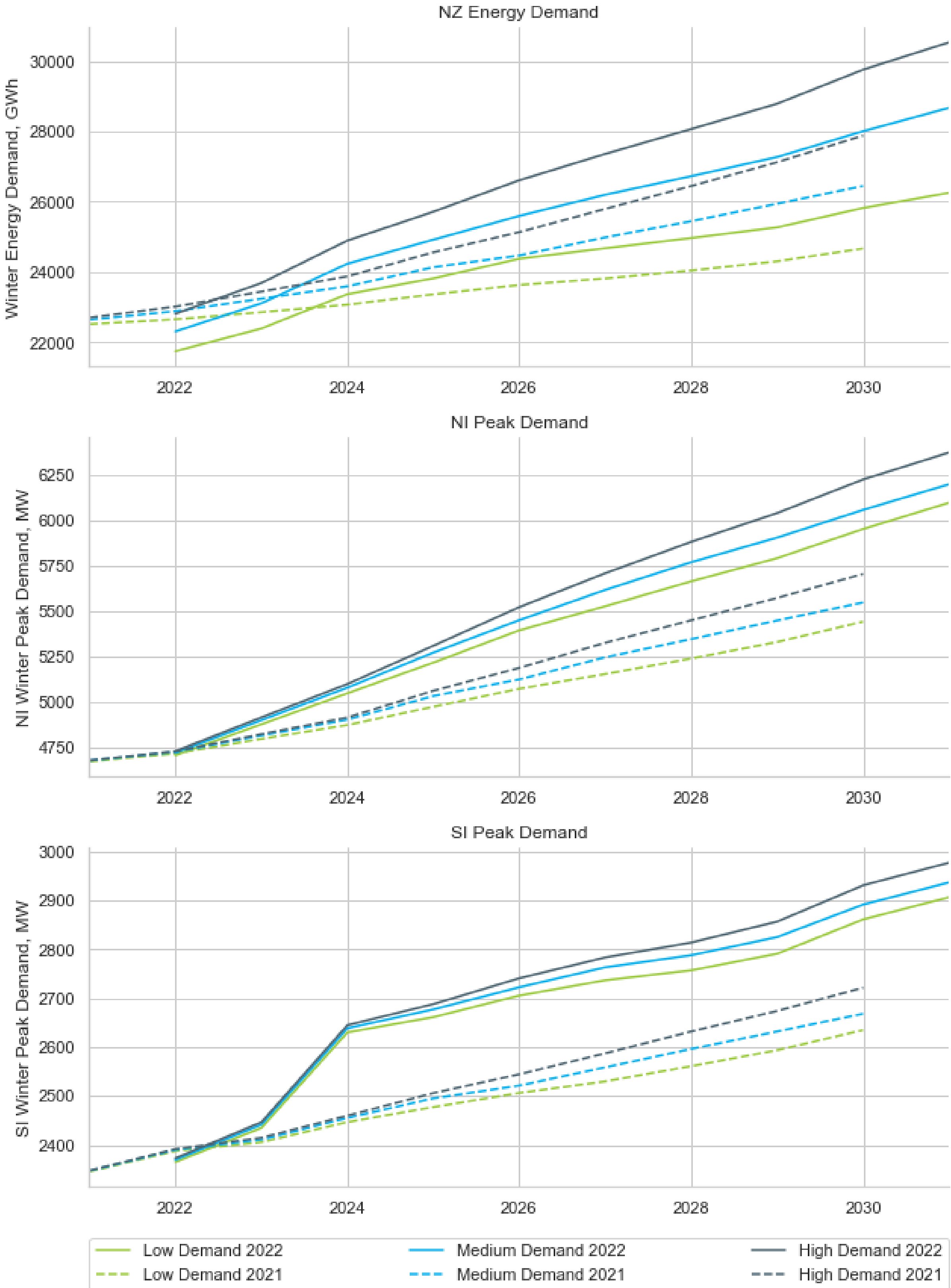
The medium demand forecast is used in the reference case, and the low and high demand forecasts are applied as demand growth sensitivities.

The winter energy and peak demand forecasts are shown in Figure 1. They include the demand forecasts used in the 2021 SOSA to show the relative increase for both energy and peak in this year's SOSA compared to last year. The NI-WCM is measured against the North Island winter peak demand forecast, with the South Island winter peak demand forecast being used as part of this calculation as it impacts the HVDC transfer.

The peak and energy demand forecast used in this year's SOSA has increased compared to the 2021 SOSA. This increase is largely due to information provided by distributors in preparing this year's demand forecast on expected increases in step loads going forward (as an example data centres and electrification of process heat).

[7] See NZ Battery Project | Ministry of Business, Innovation & Employment (mbie.govt.nz).

Figure 1: NZ winter energy, NI winter peak and SI winter peak demand forecasts compared to the 2021 SOSA



Supply

We assume existing generation used in the reference case remains available unless decommissioning has been publicly announced and is being actively pursued. Potential decommissioning and early retirement of plant is explored through sensitivities.

The potential supply pipeline is based on information provided by market participants on a confidential basis and characterised by four different stages as shown in Table 1.

Table 1: Potential supply pipeline stages

Stages	Short description	Long description of the supply pipeline stage
Stage 1	Existing and committed	Existing, consented and committed to being developed
Stage 2	Stage 1 + Consented, on hold	Includes: • Existing, consented and committed to being developed • Consented and on hold/awaiting market conditions to change
Stage 3	Stage 2 + Consented, on hold, requiring reconsent	Includes: • Existing, consented and committed to being developed • 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
Stage 4	Stage 3 + Consent expected	Includes: • Existing, consented and committed to being developed • 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, but consent likely to be sought in the next two years

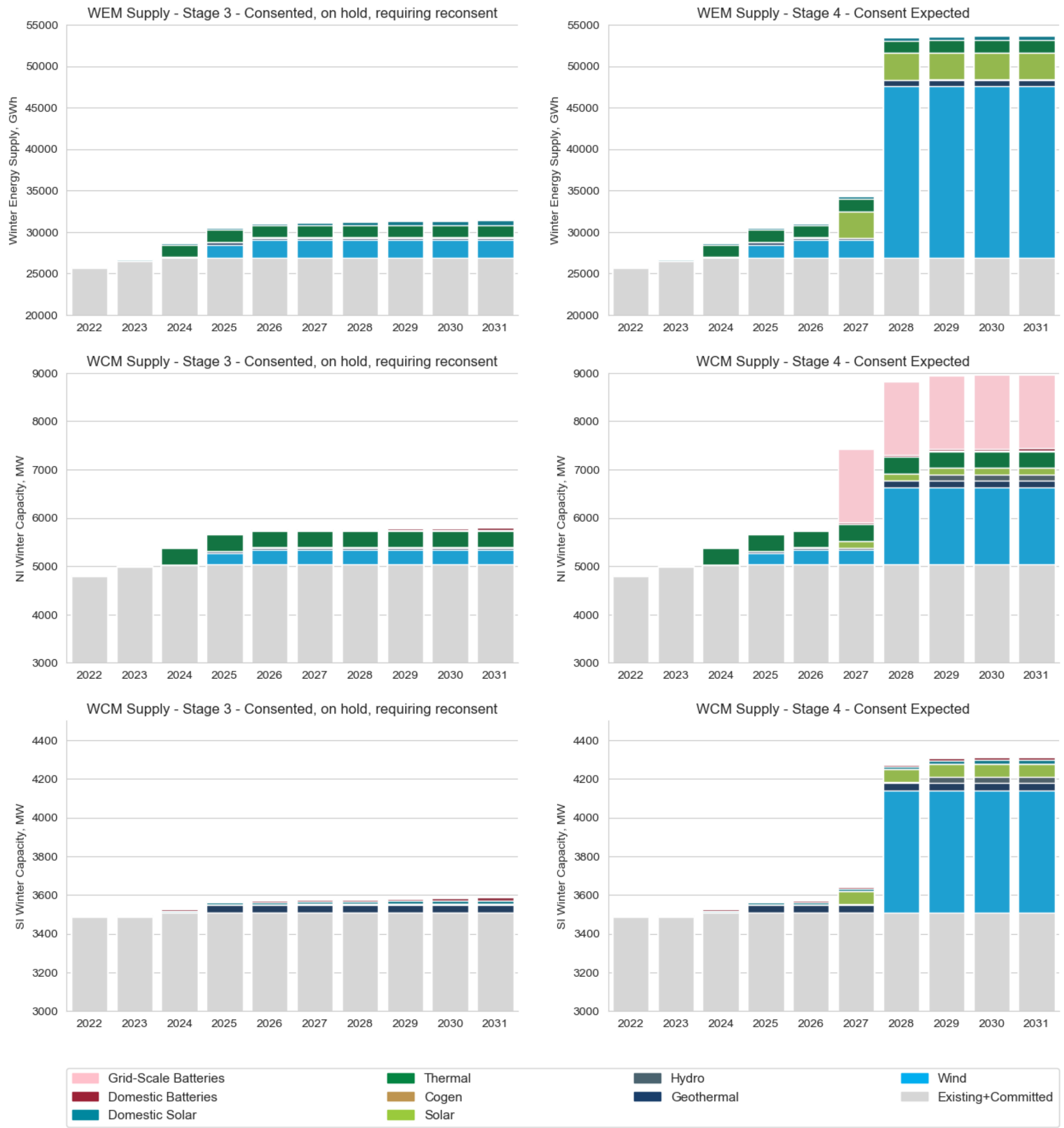
The contribution of the potential supply pipeline stages for both energy and capacity are shown Figure 2. New supply project timings are based on an estimated earliest date at which these projects could potentially be built at a given point in the future. Any subplots in Figure 2 should not be interpreted as a forecast of new generation build.

The three subplots in Figure 2 titled *Stage 3 – Consented, on hold, requiring reconsent* show the potential winter energy and capacity capability from existing and committed generation in the grey bars and the pipeline of new supply projects that are consented but on hold (some requiring reconsent).

The three subplots in Figure 2 titled *Stage 4 – Consent expected* show the potential winter energy and capacity capability from existing and committed generation in the grey bars, the pipeline of new supply projects that are consented but on hold (some requiring reconsent), and projects that are not consented but where consent is likely to be sought in the next two years. The large increase in potential contribution to winter energy and capacity margins in Stage 4 (compared to Stage 3) indicates the significant interest in new supply resources beyond those that are already consented[8]. However, given these projects are not yet consented, they have a higher degree of uncertainty in being developed.

The capacity the supply pipeline stages provide in the South Island is shown in the two subplots at the bottom of Figure 2. This capacity, less SI peak demand contributes to the calculation of the NI-WCM but is limited by the HVDC capability.

Figure 2: Contributions of potential supply pipeline to the NZ winter energy and NI winter capacity margins

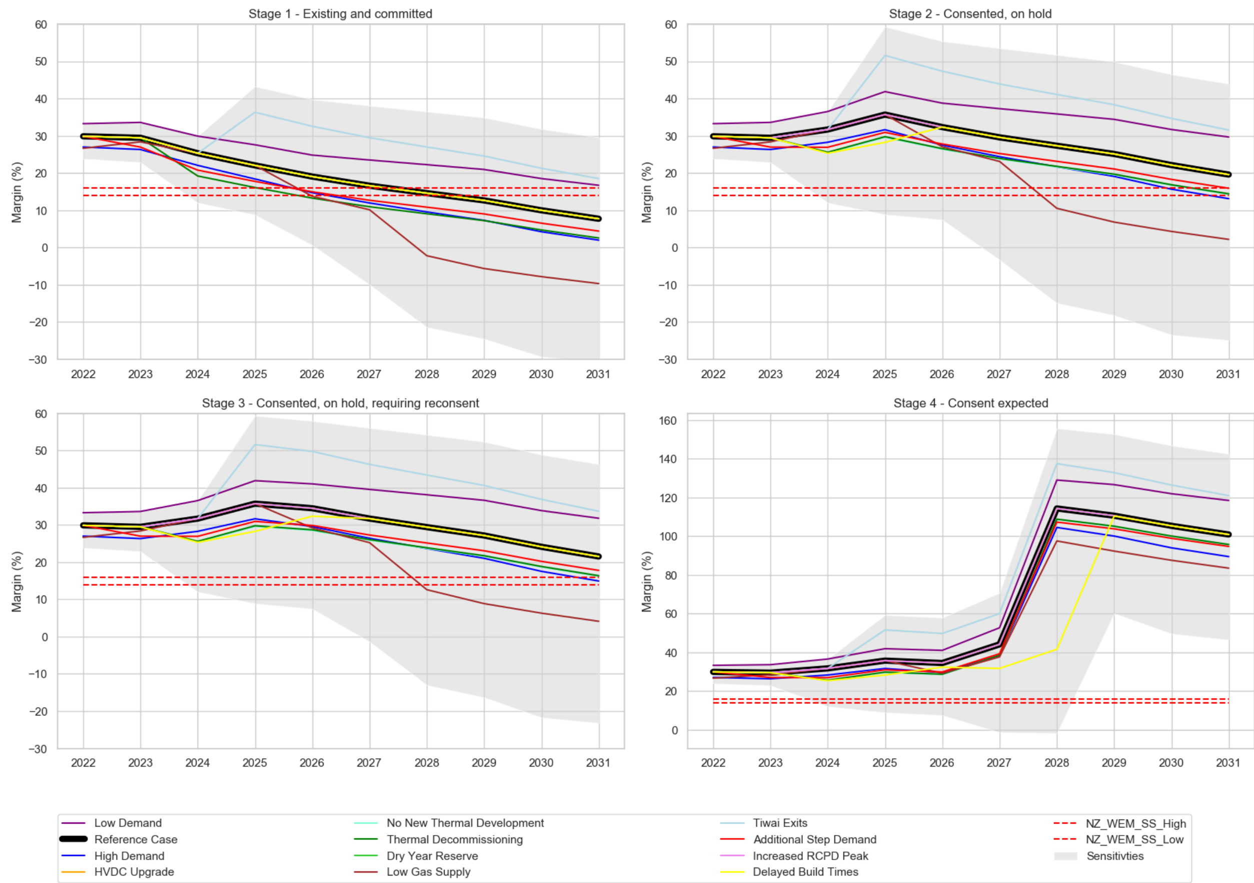


[8] This observation is supported by Transpower in its role as Grid Owner, who has seen a large increase in customer enquiries from both generation and demand, as highlighted in our Weekly Market Movements report ([Market Operations - Weekly Market Movements - 28 November 2021.pdf (transpower.co.nz)]())

New Zealand Winter Energy Margins

The NZ-WEM for the reference case, individual sensitivities and the range of sensitivity combinations are illustrated in Figure 3. The black line shows the NZ-WEM for the reference case, the coloured lines represent the NZ-WEM for individual sensitivities varied from the reference case, and the grey area represents the NZ-WEM range from our sensitivity combinations. Each graph illustrates the NZ-WEM for potential supply pipeline stages (as discussed in Table 1). The red dotted horizontal lines represent the NZ-WEM security standards.

Figure 3: NZ winter energy margin compared to the security standards



For our reference case, Figure 3 shows that:

- existing and committed projects are sufficient to maintain an adequate NZ-WEM through to 2027;
- development of projects that are currently consented and on hold would need to be commissioned by 2027 to maintain an adequate NZ-WEM through the 10-year assessment horizon beyond 2027; and
- renewable projects expecting consent in the next two years have the potential to drive a large increase in the NZ-WEM from 2028.

These results indicate the market has enough potential resources in the pipeline to maintain the NZ-WEM above the upper security standard. However, the sensitivities indicate that the maintenance of adequate margins through to 2028 (when considerable volumes of new generation could potentially be commissioned) will require:

a) the development of projects that are consented and currently on hold, including ongoing development of thermal fuels;

b) avoiding early retirement of existing generation assets; and

c) demand growth less than our medium demand forecast.

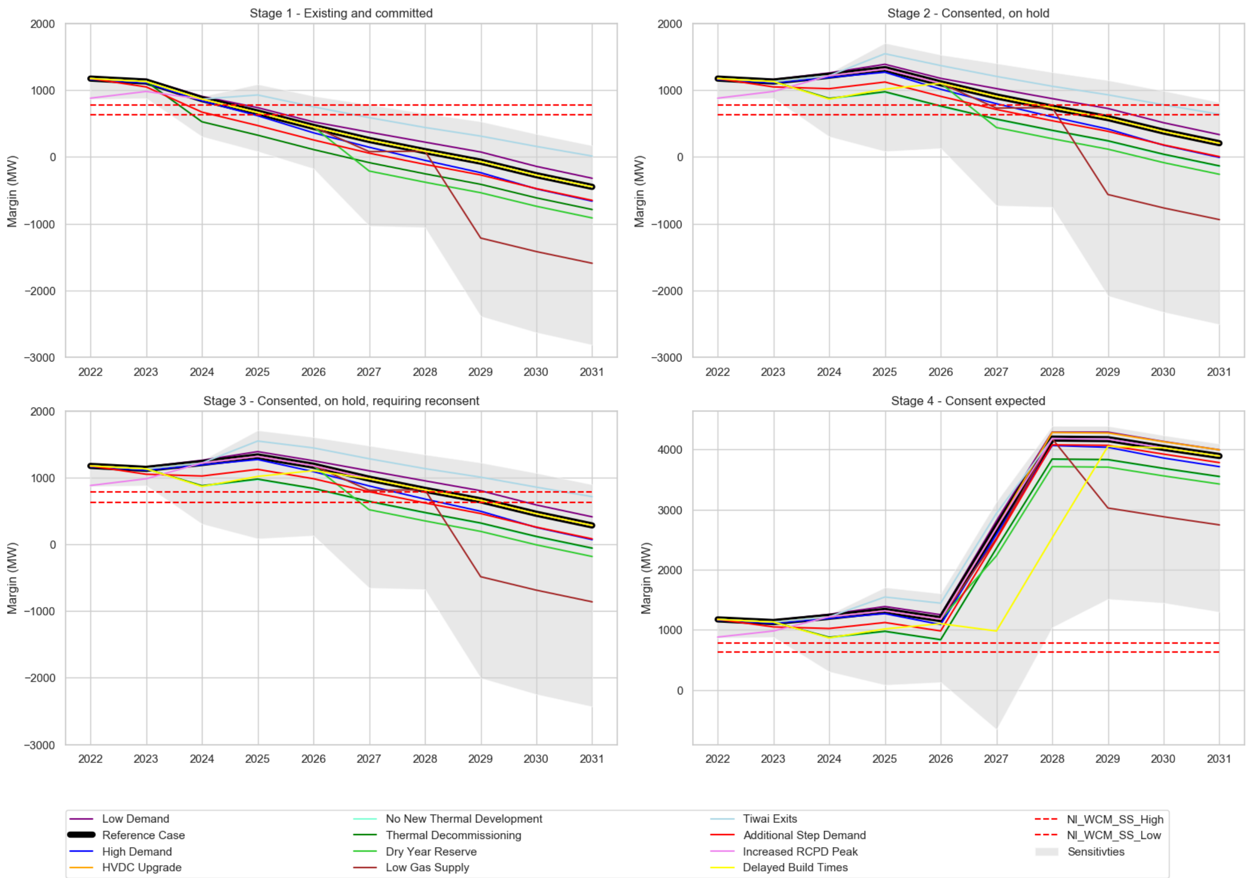
If some combination of these conditions is not met, the market would require currently unconsented projects that are likely to seek consent in the next two years to be developed in the latter half of the decade. The extent of new projects needed to be consented and built would depend on how combinations of (a), (b) and (c) being unmet diminish the NZ-WEM.

If demand is lower than forecast and/or Tiwai was to exit, it is more likely that existing and committed generation could be sufficient to keep the NZ-WEM above the upper security standard over the 10-year assessment horizon.

North Island Winter Capacity Margins

The NI-WCM for the reference case, individual sensitivities and the range of sensitivity combinations are illustrated in Figure 4. The black line shows the NI-WCM for the reference case, the coloured lines represent the NI-WCM for individual sensitivities varied from the reference case, and the grey area represents the NI-WCM range from our sensitivity combinations. Each graph illustrates the NI-WCM for the potential supply pipeline stages (as discussed in Table 1). The red dotted horizontal lines represent the NI-WCM security standards.

Figure 4: NI winter capacity margin compared to the security standards



For our reference case, Figure 4 shows that:

- existing and committed generation is sufficient to maintain the NI-WCM above the upper security standard through to 2024;
- development of all consented generation maintains the NI-WCM above the upper security standard for a further four years until 2028; and
- development of some unconsented generation that is likely to seek consent in the next two years will be required to maintain the NI-WCM above the upper security standard through to the end of the 10-year assessment horizon in 2031.

It is noted that much of the proposed unconsented generation is intermittent such as wind and solar that may not be fully available during winter peak demand[9]. As such, these generators have a lower contribution towards the capacity margin compared to the energy margin. There are also a number of unconsented battery projects in the project pipeline. These batteries have limited energy storage capability but are controllable and therefore, contribute more towards the capacity margin than to the energy margin.

The market will need to develop all the known consents to maintain the NI-WCM above the upper security standards between now and 2028, and begin commissioning projects

[9] Winter peak demand is typically experienced during cold winter evenings when solar generation is low and wind generation may or may not be high.

currently unconsented from 2028. However, even with developing all the known consents Stage 3), some sensitivities or combination of sensitivities may still result in the NI-WCM falling below the security standards prior to 2028. These are:

a) lack of development of thermal consents and reduced investment in supporting fuel supply chains, thus reducing gas production for electricity generation;

b) early retirement or reduced operation of existing generation assets; and

c) peak demand growth exceeding our medium demand forecast.

Therefore, this would require more development of currently unconsented projects.

If Tiwai were to exit, then existing and committed generation could be sufficient to keep the NI-WCM above the upper security standard to 2026. This could be extended for a further four years (to 2030) if all consented generation is developed. From 2028 there is also a large amount of unconsented potential generation that could be developed to maintain an adequate NI-WCM to the end of the 10-year assessment horizon.

Changes from the 2021 SOSA

Figure 5: NZ winter energy margin reference case comparison 2021 and 2022

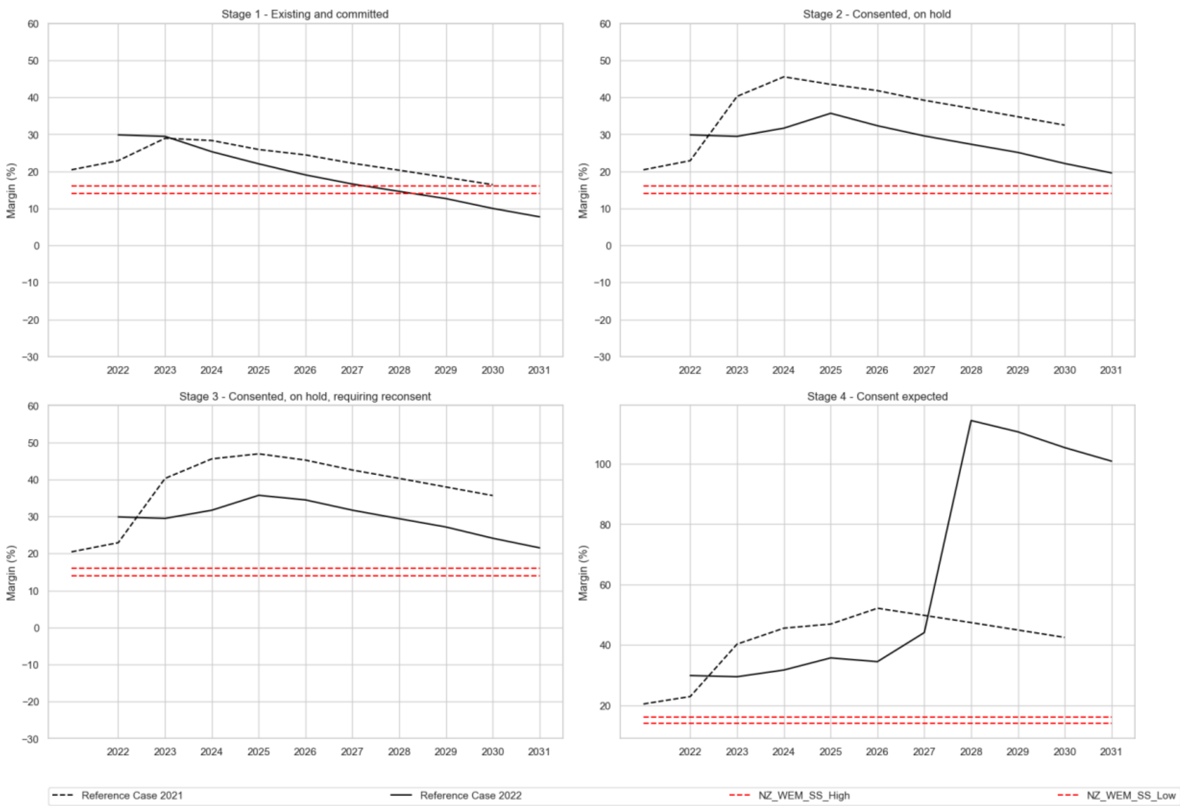
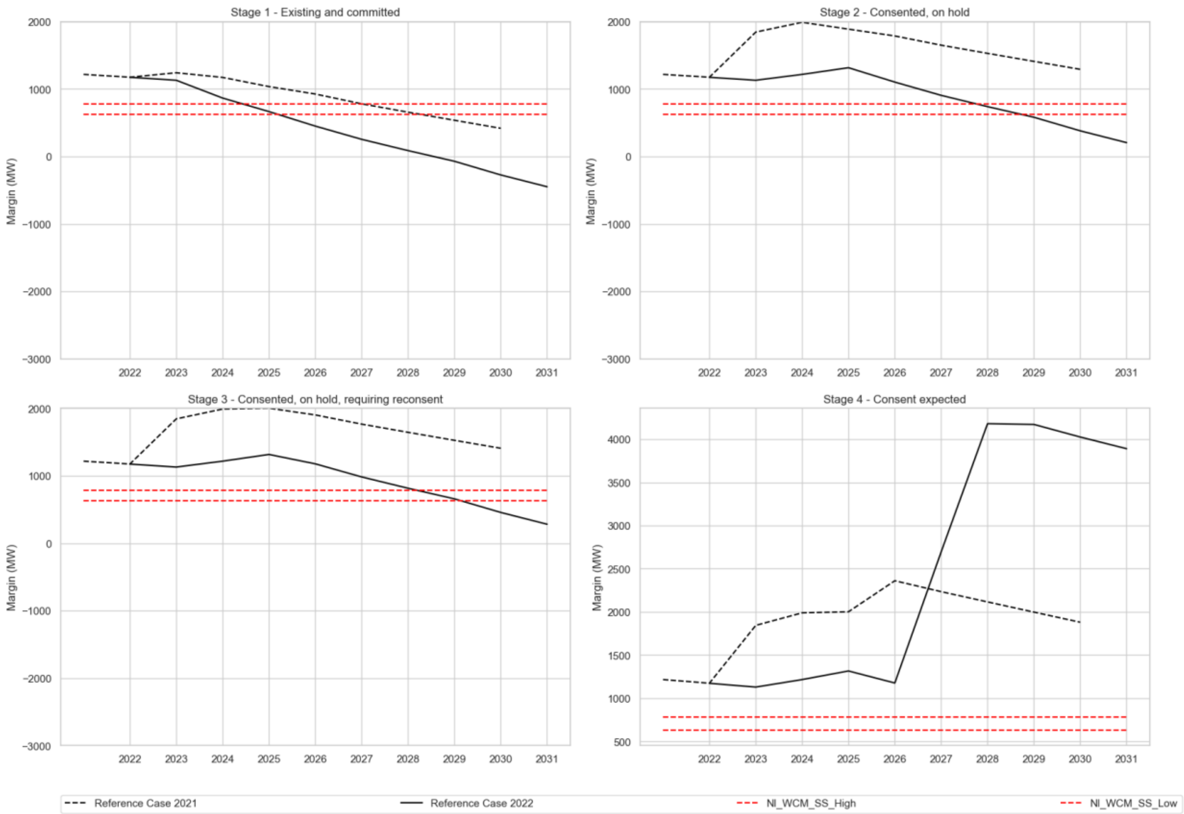


Figure 6: NI winter capacity margin reference case comparison 2021 and 2022



The winter energy and capacity margins for our reference case have declined from the equivalent case in the 2021 SOSA (i.e. the 2021 medium demand scenario combined with the 2021 Tiwai and TCC sensitivities). **Error! Reference source not found.** and Figure 6 demonstrate that the 2022 SOSA margins are lower for the initial years of the assessment horizon but increase relative to the 2021 SOSA from 2028. We attribute this to the following:

- Feedback from distributors[10] indicate an expectation of greater demand increases than shown by the 2021 SOSA. This has resulted in a significant increase in demand forecast in the demand forecasting modelling suite ('the modelling suite') used by Transpower's Grid Investment and Modelling team to forecast winter energy and peak demand compared to 2021;
- Some consents for gas generation previously included have been removed (informed by the participant survey[11]); and
- This year's margins for both energy and capacity improve relative to the 2021 SOSA from 2028 due to the large pipeline of future, unconsented renewable projects (Stage 4). This increased activity in potential new generation matches public reports from

[10] Transpower's Grid Investment and Modelling team engage with distributors to understand their expectations of future demand growth.

[11] As part of the development of the SOSA the system operator surveys participants for information on existing generation and future supply projects.

Transpower in its role as the Grid Owner who have noted an increase in renewable generation enquiries.

This year the calculated winter energy and capacity margins also indicate a wider range of values compared to the 2021 assessment. This is due to the approach we undertook this year to consider a single reference case with the winter energy and capacity margins calculated for all feasible sensitivity combinations. Therefore, combining sensitivities that each reduce (or increase) the relevant margin results in a compounding effect thus resulting in a wider range of potential outcomes than provided in the 2021 (and previous) SOSA's.

Margins with increasing proportions of renewable energy

As in the 2021 SOSA, we look at the impact on the capacity and energy margins for increasing the proportion of renewable generation in 2030. We investigate five fossil-fuel generation scenarios that consider progressively lower amounts of fossil-fuel generation. For each of these scenarios we estimate how much additional supply would be required from renewable generation and other technologies to maintain the capacity and energy margins above security standards.

This assessment shows that significant new renewable supply additions will be required to meet the demand growth, replace capacity and energy provided by existing fossil-fuelled thermal generation to increase the proportion of renewable generation to 100%, and maintain efficient levels of supply reliability[12]. New supply additions will need to include renewable projects (e.g. wind and solar) – and possibly technologies including (but not limited to) grid scale energy storage and demand response.

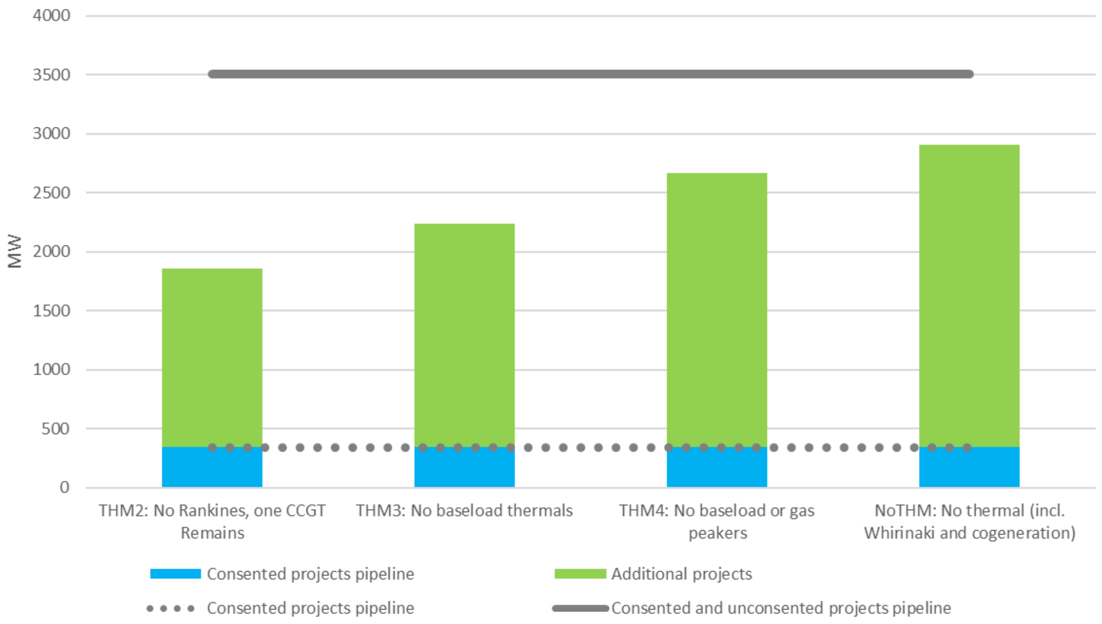
Using our reference case, to meet the demand growth and displace all fossil-fuel generation to achieve 100% renewable generation (regardless of hydro inflows) in 2030 would require progressing new supply projects to contribute around 9,700 GWh of winter energy and around 2,900 MW of winter capacity. This is an increase compared to 2021 SOSA. This is due to our 2022 SOSA reference case changing to include Tiwai thus increasing the demand. After accounting for this, the primary reason for the increase compared to last year is the increased forecast demand growth in this year's assessment. As discussed earlier this is primarily due to information provided by distributors on expectations of additional demand growth on their networks.

Figure 7 shows the new North Island[13] supply additions required for each of our fossil-fuel generation scenarios in order for the 2030 NI-WCM to be above the upper security standard. The blue bars show contributions that could come from known consented renewable projects in the project supply pipeline. The green bars show the contribution that would be required from new unconsented renewable supply projects. The dark grey dashed line shows the contribution to the NI-WCM from the consented project pipeline (Stage 3 from Table 1) and

[12] As specified by the winter energy and capacity standards in Part 7 of the Code.
[13] While our analysis only refers to the North Island WCM, South Island contributions to the margins are considered in this calculation, but are limited by the HVDC capability.

the dark grey solid line shows the same for both consented and unconsented projects that we are aware of (i.e. supply pipeline Stage 4 from Table 1).

Figure 7: Additional capacity contribution from NI projects required in 2030 to meet the NI winter capacity margin upper security standard of 780 MW



2.0 Background

This document is the system operator's medium-term security of supply assessment (SOSA). 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. The system operator performs other security of supply-related functions described in the Security of Supply Forecasting and Information Policy (SOSFIP) and the Emergency Management Policy (EMP). These include:

- assessment of Electricity Risk Curves and Stimulated Storage Trajectories over a one-to-two-year time period;
- short-term monitoring and information provision, such as the weekly reporting of hydro levels relative to the Electricity Risk Curves; and
- implementation of emergency measures where necessary.

3.0 Methodology, Reference Case and Sensitivities

3.1 Methodology

3.1.1 Winter Margins

This assessment provides a medium-term view of the balance between supply and demand in the New Zealand electricity system. It forecasts:

- the winter energy margins, for New Zealand (NZ-WEM) and the South Island (SI-WEM). These are winter energy supply, in gigawatt-hours (GWh), divided by winter energy demand, in GWh. The margins are expressed as a percentage of total demand; and
- the North Island winter capacity margin (NI-WCM)[14]. This is the sum of North Island supply capacity, less the expected peak demand, plus surplus South Island supply capacity able to be sent via the HVDC link to the North Island. The margin is expressed as a megawatt (MW) value.

Winter is defined as the period from April to October for the NI-WCM, and April to September for the NZ-WEM and SI-WEM.

The NZ-WEM and SI-WEM assess whether it is likely there will be an adequate level of supply and, in the case of the South Island, HVDC south transmission capacity, to meet expected electricity demand during the winter. The NI-WCM assesses whether it is likely there will be adequate supply and HVDC north transmission capacity to meet North Island winter peak demand.

In the context of this assessment the term *supply* includes grid connected generation, embedded generation, hydro storage and batteries.

3.1.2 Security Standards

Security standards are defined by the Electricity Authority ('the 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, where the expected cost of shortage is equal to the expected cost of new generation.

The current security standards specified in the SSAD are:

- a New Zealand winter energy margin (NZ-WEM) of 14-16%;
- a South Island winter energy margin (SI-WEM) of 25.5-30%; and
- a North Island winter capacity margin (NI-WCM) of 630-780 MW.

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[14] Note that our analysis does not make allowances for spinning reserve—that is, the peak demand is not increased by the quantity of reserves required. This means the subsequent margin represents excess supply prior to the provisioning of reserves.

Falling below the security standards does not equate to electricity shortage. Rather, it implies that investment in new generation would result in an efficient increase in 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.

3.1.3 Our Assessment

Our assessment evaluates the capacity and energy margins and compares these against the Authority's security standards. This is done for both existing generation and the pipeline of new supply projects that could be potentially built. The objectives of the assessment are to understand:

- when, and under what circumstances, the capacity and energy margins will fall below security standards if no new supply projects are built (other than those already committed); and
- whether the pipeline of new supply projects is adequate to maintain security standards assuming a stable investment environment and adequate market incentives.

While our analysis identifies when a project *could* be developed, we do not attempt to forecast *if* or *when* new supply projects will be developed. Our assessment considers a reference case and valid sensitivities and sensitivity combinations. However, because there are several thousand valid sensitivity combinations, our analysis aggregates all the valid combinations with a common sensitivity for analysis. For example, all valid combinations that contain the 'Tiwai exits' sensitivity are analysed together in comparison to the reference case.

3.2 Reference Case and Sensitivities

3.2.1 Reference Case and Sensitivities Defined

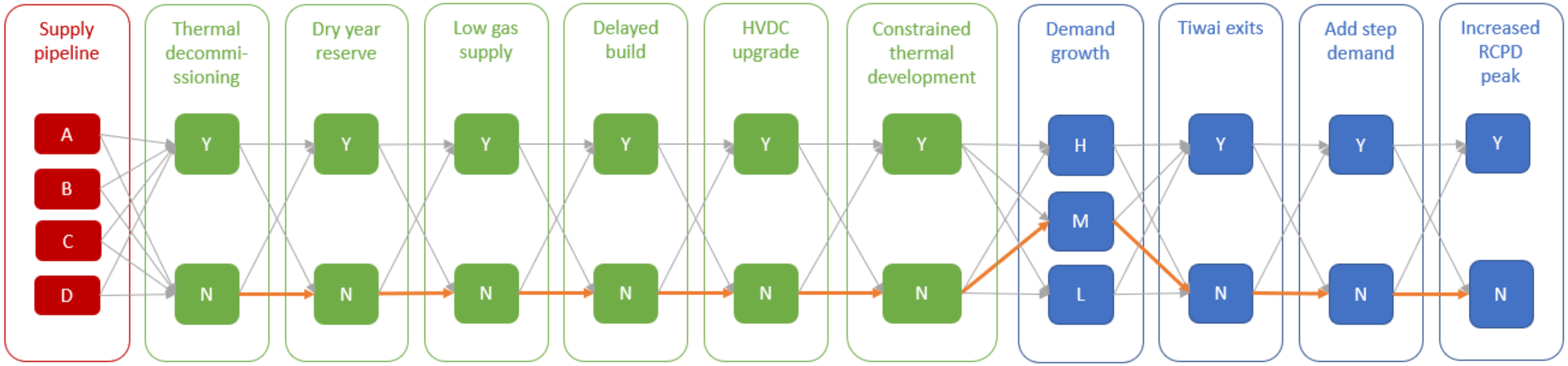
We have used a single reference scenario known as the reference case for the future New Zealand electricity system that represents the resources potentially available to the power system over the 10-year assessment horizon. The reference case represents what the market could develop, not necessarily what it will develop. In making this representation, a fixed set of assumptions are used, and these are then adjusted using several key variables, or sensitivities to test a range of plausible deviations from the reference case and the impact these have on the future capacity and energy margins. This change was generally supported during consultation with industry earlier this year.

In the reference case we assume existing generation and industrial demand will not change unless decommissioning is publicly announced, and decommissioning activities are actively being pursued. The reference case assumes a medium demand forecast and that during the 10-year assessment horizon Tiwai remains, “significant” amounts of thermal generation is not decommissioned in the near term, investment in the upstream gas sector continues, and the HVDC interconnector will not be upgraded.

The sensitivities our analysis explores are defined in Sections 3.2.3 and 3.2.4. In addition to applying individual sensitivities, valid combinations of sensitivities to the reference case are applied for a more comprehensive range of futures. Figure 8 below provides an illustration of the combinations of sensitivities.

Stakeholders are invited, and may be better placed, to make their own decisions as to which sensitivities they should have more regard to than others.

Figure 8: Assessed potential supply pipeline stages and sensitivities



Key	Future generation and grid-scale battery state
A	Existing + Committed (consented and active)
B	Consented and on hold/awaiting market conditions to change
C	Consented and on hold/awaiting market conditions to change - revision or reconsent required
D	Not consented, but consent likely sought within 2 years

Reference case

The orange arrows represent the combination of key variables that make up the reference case. The grey arrows represent the potential combinations of sensitivities.

3.2.2 Detailed Reference Case Assumptions

The following key assumptions have been used for the reference case:

Demand Growth

Our reference case will focus on a medium rate of acceleration of electrification across the economy and growth of distributed energy resources[15]. To achieve this, transport electrification (electric vehicles), and process heat electrification, solar PV and small-scale batteries are specifically modelled in this scenario.

The underlying rate of demand growth covers sectoral changes in electricity efficiency and intensity, sectoral shifts in energy demand, as well as growth of population and the economy.

Our reference case will continue to consider the impact of COVID-19 on electricity demand growth in the near term.

The increases in anticipated electrification (following feedback from distributors) has resulted in an increase in the medium energy and peak demand growth compared to the medium demand growth scenario in 2021.

Potential Supply Pipeline Stages

As in previous year's assessments, the potential supply pipeline (previously titled "future grid scale generation") is based on information provided by market participants on a confidential basis. However, in contrast to previous year's assessments, the reference case is analysed across the four potential supply pipeline stages shown in Table 2.

Table 2: Potential supply pipeline stages

Stages	Short description	Long description of the supply pipeline stage
Stage 1	Existing and committed	Existing, consented and committed to being developed
Stage 2	Stage 1 + Consented, on hold	Includes: • Existing, consented and committed to being developed • Consented and on hold/awaiting market conditions to change
Stage 3	Stage 2 + Consented, on hold, requiring reconsent	Includes: • Existing, consented and committed to being developed • Consented and on hold/awaiting market conditions to change

[15] Distributed Energy Resource provides energy and capacity at a household level offsetting Grid demand. For this reason, the expected rate of uptake is modelled in the demand forecast rather than as a supply sensitivity.

Stages	Short description	Long description of the supply pipeline stage
		• Consented and on hold/awaiting market conditions to change - consent revision, or reconsenting will be required
Stage 4	Stage 3 + Consent expected	Includes: • Existing, consented and committed to being developed • 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, but consent likely to be sought in the next two years

We assume that existing generation remains available unless decommissioning is publicly announced, and decommissioning activities are being actively pursued.

Tiwai Smelter Load

The reference case includes the Tiwai smelter load over the 10-year assessment horizon. The current Tiwai contract is scheduled to expire at the end of 2024. However, New Zealand Aluminium Smelters (NZAS) have indicated that it intends to remain operating beyond this date.

Gas Supply

For our reference case the gas supply availability (for gas generation) has been assessed by estimating a dry year gas supply margin for the 10-year assessment horizon as used in the 2021 SOSA[16]. Gas supply assumptions use confidential information from gas producers for 2022 - 2023 and Ministry of Business Innovation and Employment (MBIE) statistics[17] for the latter years.

Using our assumptions as outlined in Section 4.0, dry year gas supply margins indicate there is expected to be sufficient gas to run over winter periods under the reference case. This is primarily due to expected ongoing investments in the gas sector to enable additional gas supply over the coming years including the development of potentially recoverable contingent reserves, assuming reallocation of gas from industrial gas users if needed for increased electricity generation during dry years and substitution of gas demand from industrial processes.

[16] Previous Security of Supply Assessments
[17] MBIE's Petroleum Reserves 2020

HVDC Capacity

The reference case assumes that the HVDC will not be upgraded throughout the 10-year assessment horizon. The capacity of the HVDC is as described in the Authority's SSAD.

3.2.3 Supply Side Sensitivities

Thermal Decommissioning

This sensitivity tests the potential impact of the near-term[18] decommissioning of a significant fossil-fuelled thermal generation asset. Because Contact Energy have publicly indicated the potential for decommissioning TCC by end of 2023[19] we have used this as the example in this sensitivity. We previously considered assuming TCC not contributing to the NI-WCM when in operation, however, note that TCC is typically in operation during winter periods when North Island peak load periods are likely to occur. Therefore, we have refined this sensitivity so that TCC contributes to the NI-WCM when in operation (as in the reference case).

Dry Year Reserve

This sensitivity assumes a small number of 'baseload' fossil-fuelled thermal generators change their operation so that they only provide dry year reserve from 2027 onwards. This sensitivity tests the impact on the NI-WCM if these generators were not available to contribute to short term, unanticipated, supply shortages (unrelated to hydrology). Existing fossil-fuelled thermal generation installed capacity will be reduced by 480MW when calculating the NI-WCM. As this capacity will still be available for dry year reserve, it will still be included when calculating both the NZ-WEM and SI-WEM.

Low Gas Supply

This sensitivity is intended to show a constrained case of gas supply for electricity generation over the 10-year assessment period[20]. It reflects concerns that future capital investment in the upstream gas industry may be at risk, given anticipated changes in gas demand and perceived uncertainties as to the transition away from carbon intensive fossil fuels. Further information can be found in the Gas Industry Company's Gas Market Settings Investigation[21] final report.

In this sensitivity, we assume that gas supply post-2025 is limited to estimated 1P reserves, where these are known reserves that have a 90% chance of being 'recovered' or produced. We also assume that there are no efforts to unlock contingent gas resources or to import

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[18] This is in the next 1-2 years.

[19] See page 44 (exhibit 19) of the Contact report "'Crafting a path for New Zealand's 100% renewable electricity market'" available here and slide 12 of Contact's 2021 UBS Australasia presentation available here.

[20] This sensitivity is based on the low gas supply sensitivity assessed in the 2021 Security of Supply Assessment.

[21] Gas Market Settings Investigation.

natural gas. This is consistent with this sensitivity's underlying assumption of minimal levels of investment in upstream gas sector infrastructure. Domestic gas production begins to decline substantially from 2026. In addition to reduced gas supply, in this sensitivity we also assume less gas demand reallocation occurs from industrial gas users when needed for increased electricity generation. These result in a progressive curtailment of existing gas generation, with only gas cogeneration plant contributing to security margins from 2030.

Delayed build times

This sensitivity explores the impact of delaying the commissioning dates for all new generation by one year. This sensitivity is intended to cover a range of possible eventualities. For example, new generation may be delayed due to transmission constraints, resource consent issues or investment uncertainty.

HVDC upgrade

The exit of Tiwai and/or new South Island generation capacity may result in surplus South Island generation capability that could be exported to load centres in the North Island which could result in the upgrade of the HVDC link including adding a fourth cable. The Net Zero Grid Pathways (NZGP) scenarios considers the earliest this could occur is 2027[22].

Constrained thermal development

In this sensitivity we consider the impact if no new fossil-fuel generation is developed during the 10-year assessment horizon (2022-2031). This could be for a variety of reasons as we transition towards lower carbon economy.

3.2.4 Demand Side Sensitivities

Demand growth

The demand growth sensitivities explore higher and lower rates of electricity demand growth compared to the reference case. Each of these will differ by varying the rates of acceleration of electrification across the economy and growth of distributed energy resources. To achieve this, transport electrification (electric vehicles), and process heat electrification, are specifically modelled for each growth rate. Different rates of solar PV and small-scale batteries are also modelled as they can offset growth in demand from the grid.

Tiwai exits

This sensitivity assumes that the Tiwai aluminium smelter exits the New Zealand market when its current contract expires (at the end of 2024). In this sensitivity we assume a "hard" exit, with no ramp down in demand from the smelter up to and including 2024.

[22] See Page 40 of the Net Zero Grid Pathways (NZGP)

Step change increase in demand

This sensitivity explores the potential impact of new industrial sources of demand such as data centres, other new industries, or electrification of process heat demand. In this sensitivity we consider an additional step of load in both the North and South Islands.

Change in peak transmission pricing

This sensitivity considers the potential peak demand increases as the electricity sector adjusts to a change in transmission pricing.

The revised Transmission Pricing Methodology removes the use of Regional Coincident Peak Demand in allocating transmission interconnection charges. The new Transmission Pricing Methodology (without RCPD allocation) will come into effect in April 2023. This implies the use of RCPD (from September 2021) will not be used for allocating interconnection charges. This in turn removes a direct price incentive for Transpower customers (distributors and directly connected consumers) to control load at peak times.

We anticipate this will result in an increase in peak demand. This increase could be muted, given that existing load control activities will still be used to manage local distribution constraints or spot market exposure. We also anticipate that this increase in peak demand will likely be temporary. Arrangements will likely eventually be made to take advantage of any underutilised load control facilities to, for example, manage wholesale risk or local transmission constraints.

Based on a survey of distributors and an analysis of directly connected consumer demand, we estimate that peak demand may increase (from forecast levels) in 2022 by 236 MW in the North Island and 68 MW in the South Island. In 2023, the sensitivity lowers this increase in winter peak demand by 50%, and in 2024 we assume winter peak demand returns to forecast levels.

4.0 Assumptions

4.1 Demand Assumptions

4.1.1 Forecasting Approach

Winter energy and peak demand forecasts are developed by Transpower's Grid Investment and Modelling team and align with those used for transmission planning and strategic planning. They are developed following a three-step process[23] as shown in Figure 9.

Stage one: Forecast underlying demand growth rate

This stage forecasts the underlying demand growth rate. Inputs to this forecast include expected changes in population and Gross Domestic Product, historic demand growth rates and demand forecasts from distributors.

Stage two: Add changes in demand from new technologies

In this stage demand changes for electric vehicle charging, domestic solar PV, domestic batteries and process heat electrification are added in, considering the regional, seasonal and sectoral impact of these technologies. Consideration is given to how some technologies alter the demand for electricity within a typical day. For example, we assume that smart[24] electric vehicle charging will be set up to charge electric cars during periods of low demand – acting to 'fill-in' demand troughs.

While the demand forecasts consider embedded generation, only the uptake of domestic solar PV is forecast[25]. Other types of embedded generation are assumed to remain at current levels, as derived from historic market information[26].

Inputs to this stage include forecast uptake rates of new technologies (see Table 3). Outputs from this stage are forecast demand - and its components - broken down by grid exit point (GXP) and half hourly trading period.

Stage three: Calculate winter energy and capacity demand

For this final stage the forecast winter energy and peak demand are calculated.

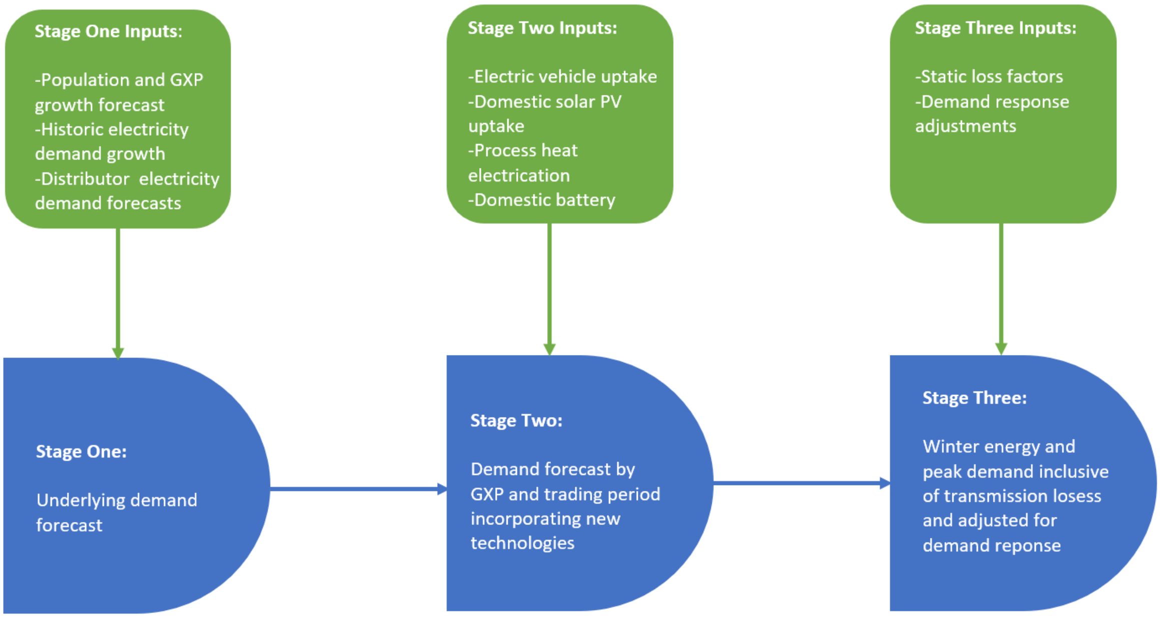
Winter energy demand is calculated by summing the stage two forecast demand, over each GXP in both islands, and over each winter half hour period. Winter peak demand is calculated

[23] This process is similar to that used in the 2021 SOSA.
[24] In this context smart electric vehicle charging refers to technology that avoids electric vehicle charging due peak demand or high price periods.
[25] Domestic solar PV could increase as the number of households increase as well as greater proportion of households adopting solar PV.
[26] Adjustments are made for other embedded generation if we are informed of changes by distributors or customers.

by averaging the stage two forecast demand, over each island, and over the highest 200 half hours of winter daytime demand[27].

Forecast winter energy and peak demand, as used in our assessment, is on a gross basis, includes transmission losses and is adjusted for demand response. Gross demand can be thought of as the total demand seen by the national grid and distribution networks. It is the demand served by both embedded generation and grid connected generation. Transmission losses are calculated by calculating GXP offtake quantities and applying a static loss factor. Demand response adjustments are detailed in Appendix 2.

Figure 9: Diagram of demand forecasting process



4.1.2 New Technology Uptake Rates

New technology uptake rates leverage the work from Whakamana i Te Mauri Hiko and vary for each scenario as shown in Table 3.

Table 3: Technology uptake rates mapped to Whakamana i Te Mauri Hiko scenarios

Demand Scenarios	Whakamana i Te Mauri Hiko Scenario	Description
Low Demand (Sensitivity)	A blended mix of Business as Usual and Measured	Some electrification of transport and process heat fails to emerge as compared to the medium and high demand sensitivities. This may reflect stalled technology development or

[27] This calculation of winter peak demand (also called the H100 demand) for use in the winter capacity margin calculation is specified in the SSAD.

Demand Scenarios	Whakamana i Te Mauri Hiko Scenario	Description
	Action with greater EV uptake	if regulatory settings do not achieve their intended goals. It could also be consistent with a future where other alternatives to decarbonisation are pursued, such as forestry abatement.
Medium Demand (Reference Case)	Accelerated Electrification with greater EV uptake	Technology uptake rates represent a realistic yet aspirational scenario for the New Zealand economy and electricity industry. This will require integrated, coordinated planning and action from across the economy and government.
High Demand (Sensitivity)	Mobilise to Decarbonise	There is a much stronger and more urgent response to climate change. It is not the rate of development of technologies that will change under this scenario, but rather the strength of the decarbonisation effort. While this scenario has more domestic solar uptake, it has little impact on reducing the winter peak demand.

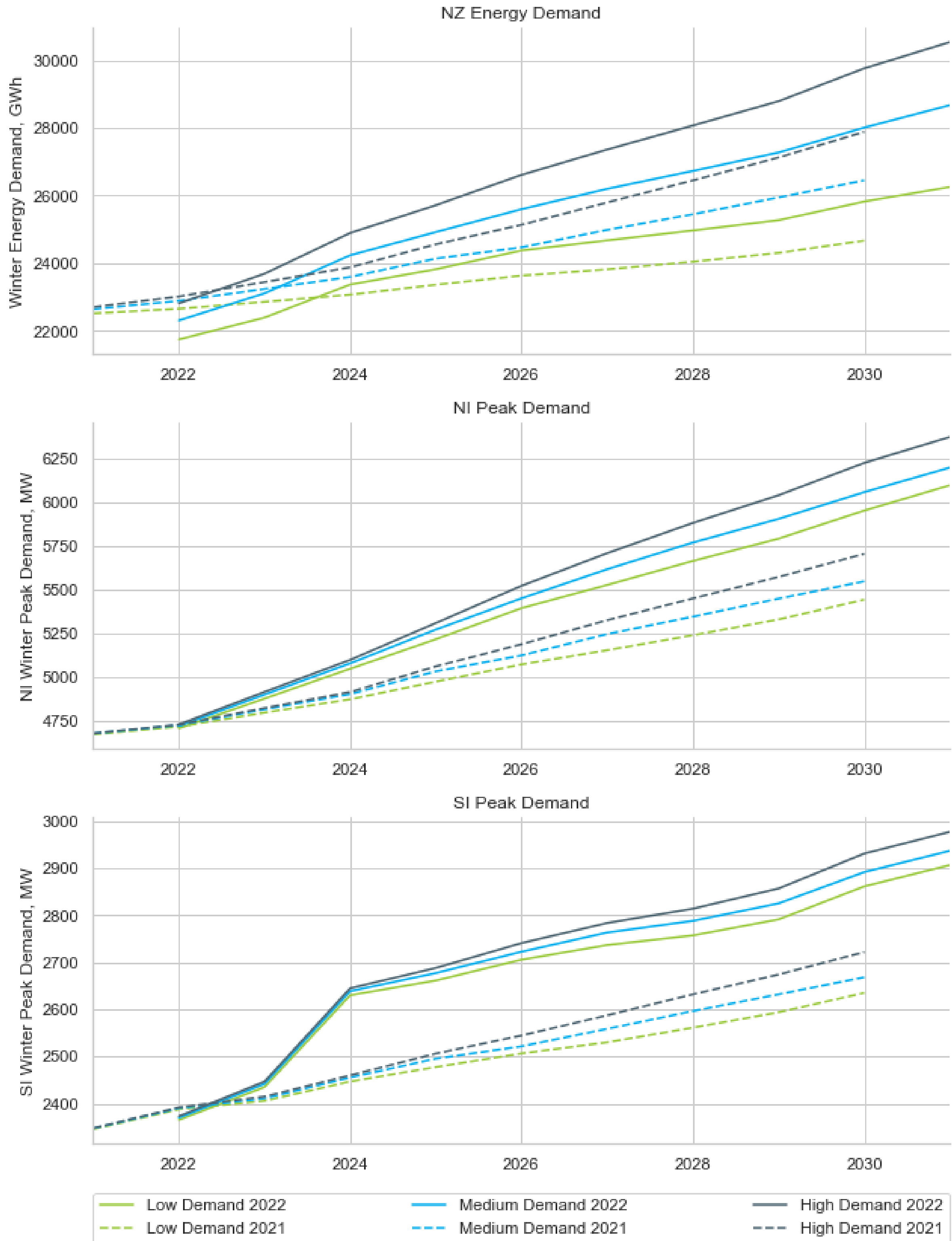
4.1.3 Forecasts

Figure 10 shows forecast winter energy and peak demand as used in this analysis. The demand shown is gross, includes transmission losses, but excludes demand response. While demand response is not shown below, it is included in our margin analysis[28]. The NZ energy forecast is consistent with our reference case assumptions which includes the Tiwai smelter load.

The forecast incorporates demand reductions at the Norske Skog's Tasman pulp and paper mill at Kawerau and Refining New Zealand's Marsden Point Refinery.

[28] Demand response assumptions are based on the SSAD. This specifies 2% demand response in the WEM calculation and 176 MW when calculating the WCM.

Figure 10: NZ winter energy and island winter peak demand forecast for 2021 and 2022 SOSA



Comparison with the 2021 SOSA

Figure 10 compares forecast New Zealand winter energy and island winter peak demand forecast for this year's SOSA and the forecast used in the 2021 SOSA. There is an increase in this year's forecast compared to the 2021 SOSA. This increase is largely due to information provided by distributors in preparing this year's load forecast on expected increases in step loads going forward (as an example data centres and electrification of process heat). This increase is primarily in the North Island as observed by the increased North Island winter peak demand however there is some step load increase in the SI as well as observed in the SI peak load increase from 2023 to 2024.

Other changes to the forecast compared to 2021 are the adjustments due to COVID-19 effects. The demand forecast used in the 2021 SOSA was adjusted so that it grew from the 2019 demand as if it repeated that seen in 2020. This was used for the low, medium and high demand forecasts. This year, different COVID-19 adjustment effects were assumed for the low, medium and high demand forecasts (essentially considering potential longer-term COVID-19 effects on the demand forecasts). These adjustments are:

- for the low demand forecast: a longer-term effect of COVID-19 was assumed in reducing demand growth with the forecast adjusted so that it grew from the 2021[29] demand;
- for the high demand forecast: no longer-term effect of COVID-19 was assumed in reducing demand growth with the forecast adjusted so that it grew from the 2019 demand as if it occurred in 2021; and
- for the medium demand forecast: an average impact (between the high and low forecast) was considered with the forecast adjusted so that it grew from the average of the last 3 years (2019-2021) as if it occurred in 2021.

Comparison with Ministry of Business, Innovation and Employment's forecasts

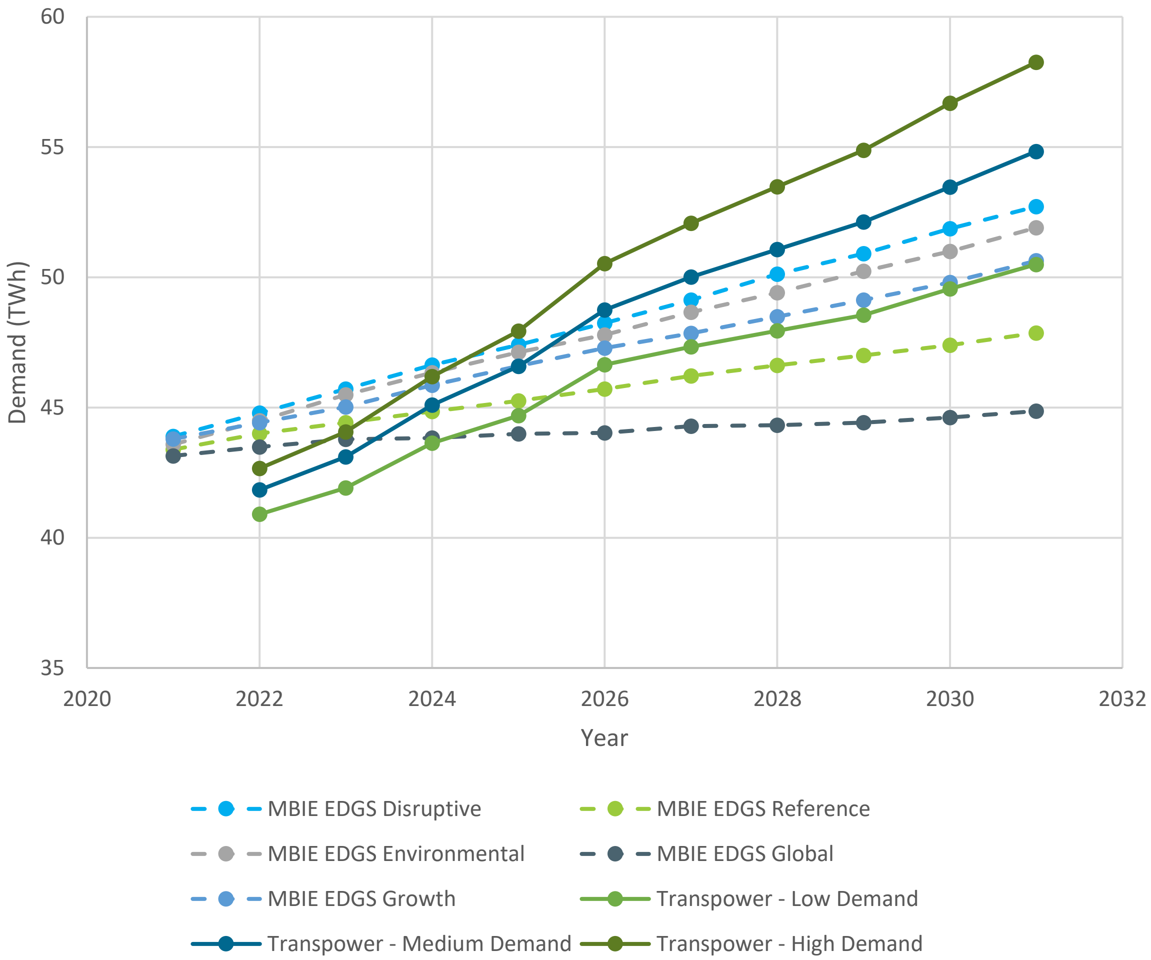
Figure 11 shows annual energy demand for our scenario forecasts (solid lines) compared to the Ministry of Business, Innovation and Employment's (MBIE's) electricity demand and generation scenario forecasts published in 2019 (dashed lines). MBIE prepares an independent set of scenarios that enable the Commerce Commission to assess Transpower's Grid Owner planning proposals for future capital investment in the electricity transmission grid. To align with the Tiwai assumptions in our reference case, both our and MBIE's forecasts has Tiwai remaining in these forecast comparisons.

Given the expected increases in electrification (step loads) with more recent data provided by distributors, the latest demand forecast starts within the range of MBIE set of scenarios but tracks higher than the MBIE range of forecasts in the later years. This is also in part due

[29] There has been a reduction in the national energy consumption over the last 3 years (2019, 2020 and 2021).

to the MBIE forecast last being updated in 2019 and potentially not capturing the latest expectations of increased electrification of the economy.

Figure 11 Annual energy demand forecasts combined to MBIE's forecasts



4.2 Supply Assumptions

4.2.1 Information Sources

Information on existing and proposed new supply projects are obtained from generation companies on a confidential basis.

4.2.2 Winter Energy and Capacity Supply Contributions

Winter energy and capacity supply contributions include generation from both grid connected and embedded generation. Table 4 shows how contributions are evaluated for different types of generation.

Table 4: Evaluating winter energy and capacity contributions

Resource type	Energy contribution	Capacity contribution
Fossil-fuel thermal generation	Installed capacity, de-rated for outages, and multiplied by the number of winter hours.	Installed capacity, de-rated for outages.
Controlled hydro	Generation based on average hydro inflows over the historic record.	Installed capacity, de-rated for outages.
Other major sources of generation This includes all generation offered into the spot market (with a handful of exceptions)	Installed capacity, multiplied by the expected capacity factor, and then multiplied by the number of winter hours. The expected capacity factor is as reported by generation companies supplemented by historic market information.	Installed capacity multiplied by a resource specific winter peak contribution factor. The ‘resource specific winter peak contribution factor’ is 25% for wind and based on historical winter peak contributions for other resources. A 5% winter peak contribution is used for large-scale solar.

Resource type	Energy contribution	Capacity contribution
Grid-connected batteries	No energy contribution assumed[30].	Installed capacity, de-rated for outages.
Smaller embedded generation (excluding domestic solar PV)	As per historic market information. No forecast changes assumed unless information provided by customers on changes.	As per historic market information. No forecast changes assumed unless information provided by customers on changes.
Domestic solar PV and batteries[31]	As per the demand forecast.	As per the demand forecast.

4.2.3 New Supply Projects

Proposed new supply projects have been aggregated to preserve confidentiality. To give a broad indication of the likelihood that development will proceed we have allocated each new supply project into four supply pipeline categories[32]:

- Existing, consented and committed to being developed;
- 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; and
- Not consented but consent likely to be sought in the next two years.

The earliest dates at which a new supply project could potentially become available is based on the type of project and its development category. This is shown in Table 5. New supply project additions by their earliest build year are also shown in Figure 12.

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[30] Grid connected batteries will both generate power into and consume power from the grid. The net efficiency loss will imply they will be a net load on the system. Our assessment based on the expected grid-connected battery supply (from participant surveys) was an expected increase in load of ~0.1%. Given this small effect, we have assumed no significant impact on the net load in this year's assessment.

[31] Both the domestic PV and batteries included in the demand forecast are done at a regional level and include regional diversities. No further deratings are applied to these forecasts.

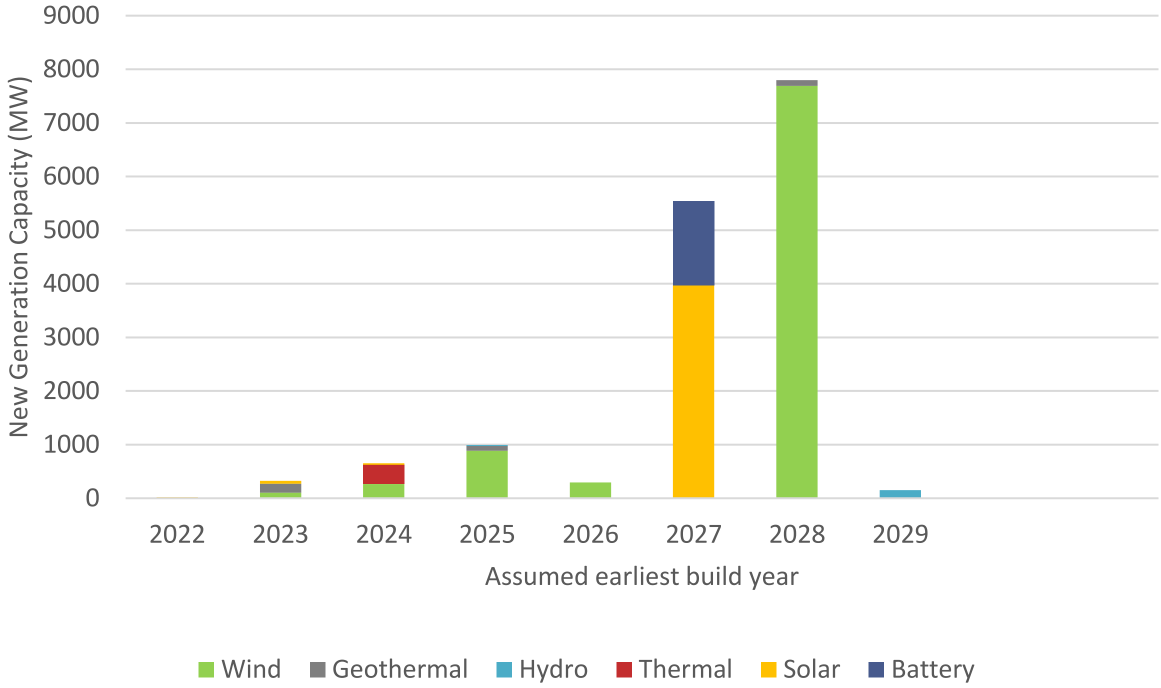
[32] We refer to these different supply pipelines as Stages 1-4 in some of our plots.

Table 5: New supply project, earliest build dates by project type and development category

	Existing and committed	Consented, on hold	Consented, on hold, requiring reconsent	Consent expected
Fossil-fuel thermal	Estimated build date	2024	2025	2027
Geothermal	Estimated build date	2025	2026	2028
Wind	Estimated build date	2025	2026	2028
Hydro	Estimated build date	2026	2027	2029
Solar (large scale)	Estimated build date	2024	2025	2027
Battery	Estimated build date	2024	2025	2027

The above timeframes allow us to project the size of the pipeline of new supply projects at a given point in the future. Our earliest build dates are an estimate of when generation *could potentially* be built at a given point in the future. New supply projects will most likely be progressed only when the market conditions justify investment. Delays may occur for a variety of reasons, including due to plant availability, logistics, and transmission requirements. It also possible that projects may be expediated to respond to market conditions. It is possible therefore that actual build dates for a given new supply project could be many years later than our estimated earliest build date.

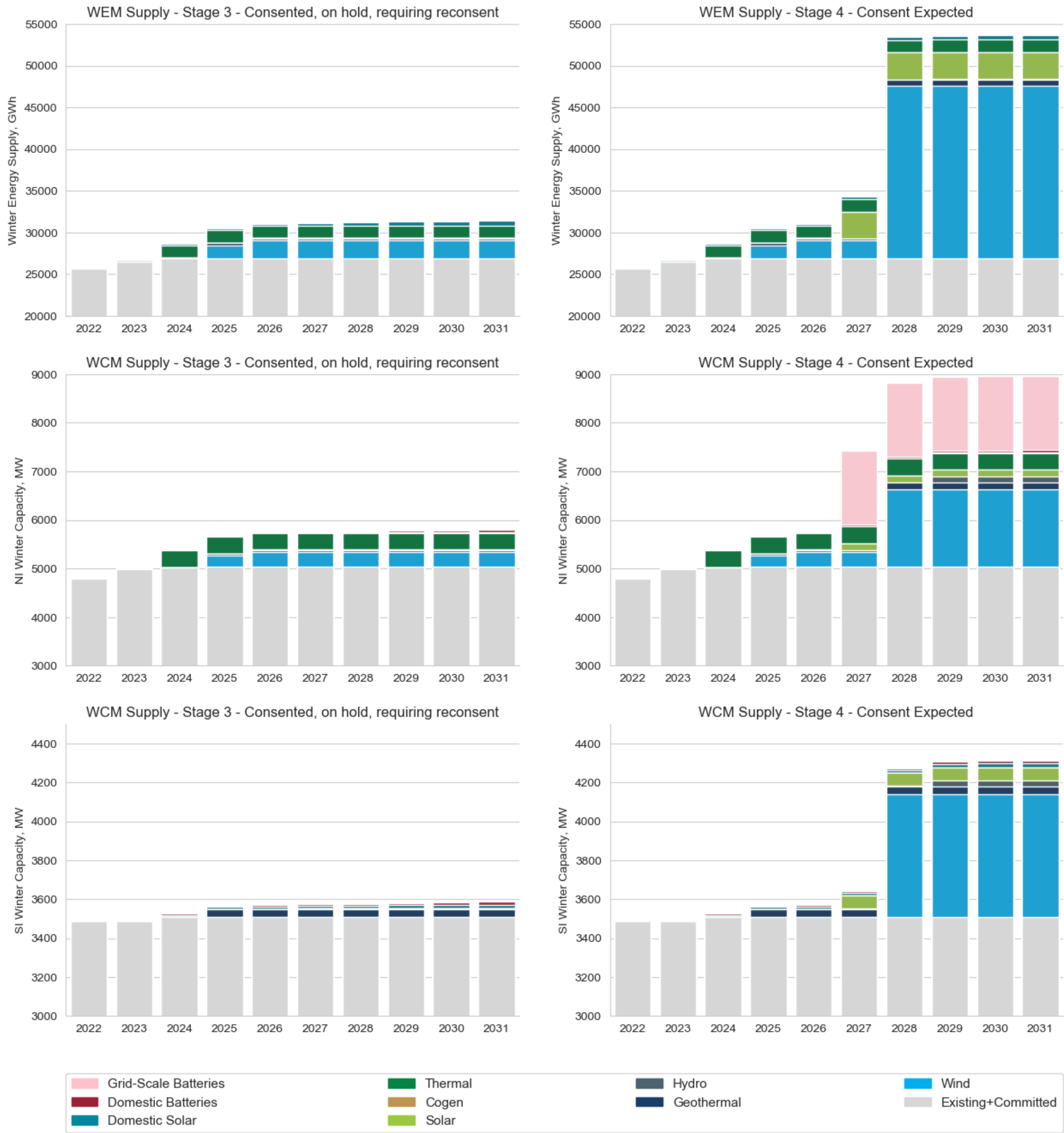
Figure 12: New supply project timeline for the reference case and demand growth sensitivities (excluding domestic solar and batteries)



4.2.4 Winter Energy Supply and Capacity

Assumed winter energy supply and capacity are shown in Figure 13. The grey bars show existing and committed generation. The coloured bars are our forecast of the pipeline of new supply projects for supply pipeline stages 3 and 4 (as described in Table 1). Each coloured bar represents cumulative new supply projects for a given fuel type and year.

Figure 13: Winter energy and peak supply (storage and de-ratings excluded)



Changes in Supply from the 2021 SOSA

Changes in winter energy and capacity supply assumptions compared to the 2021 SOSA are shown in Figure 14.

From the completed participant survey this year we have seen two major shifts compared to the 2021 SOSA:

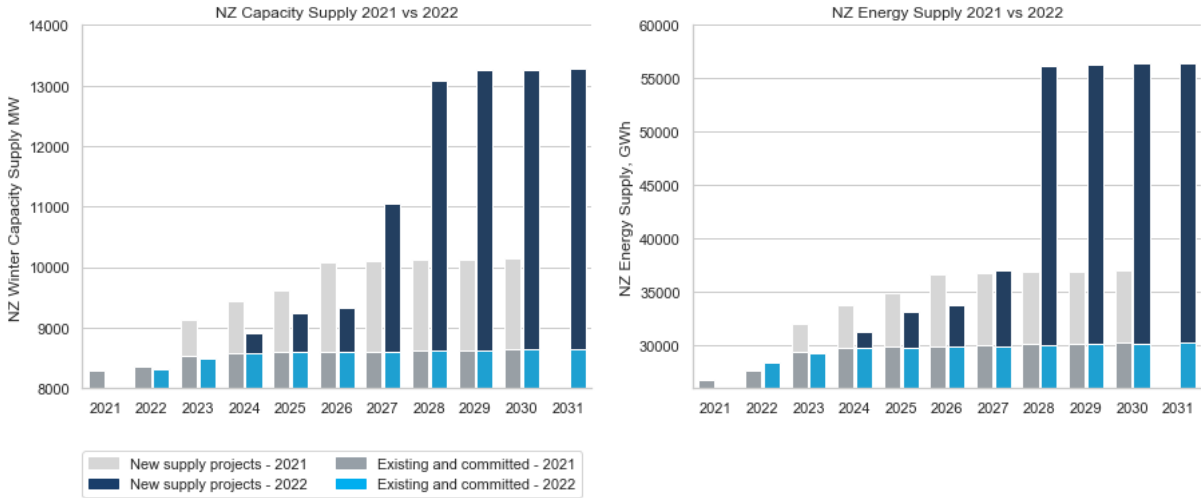
- less new fossil-fuelled thermal generation capacity in the short-term

- more intermittent generation capacity (wind and solar) and batteries in the medium to long term.

This results in an overall decline in the capacity additions in the short-to-medium term but an increase in the medium-to-longer term.

It should however be noted that most of this medium-to-long-term wind, solar and battery capacity is not currently consented and although we see a large increase in the supply pipeline towards the end of the 10-year assessment horizon, there is greater uncertainty associated with these unconsented capacity additions.

Figure 14: Winter energy and capacity supply as compared to the 2021 SOSA



4.2.5 Thermal Fuel Availability

Gas and coal availability

Gas supply availability for gas generation has been assessed by estimating a dry year gas supply margin for the 10-year assessment horizon. This margin calculates the average daily difference for gas supply and demand (across all gas users) during a dry year emergency. The dry year gas supply margin assumes that the:

- Huntly Rankine units are operating on coal;
- gas reallocation occurs from industrial gas users to increase gas-fuelled electricity generation during dry years;[33]

[33] These amounts are similar to those observed during 2021. We note the system operator is undertaking a consultation on the Security of Supply Forecasting and Information Policy. Included in the scope of the consultation is the treatment of gas reallocation from industrial gas users to electricity generation during dry years when determining the Electricity Risk Curves. The Gas Industry Company (GIC) in its recent Supply-Demand projections also assumes that substitution from industrial gas users to electricity generation (as occurred in 2021) will continue for future tight supply/demand balance situations. In our low gas supply sensitivity we consider less gas reallocated from industrial gas users for increased electricity generation.

- there will be a substitution of gas demand from industrial processing to electricity generation; and
- in general, Ahuroa Gas Storage facility has enough gas stored to operate at its maximum extraction rate throughout a dry year emergency.

This analysis is discussed further in Appendix 2.

Gas supply assumptions use confidential information from gas producers for 2022-2023 and Ministry of Business Innovation and Employment statistics for latter years.

Using the above assumptions, the dry year gas supply margins indicate that there is expected to be sufficient gas to run over winter periods under the reference case. This assumption includes ongoing investment to gas fields to maintain sufficient fuel for gas-fired electricity generation needs over the coming years.

Coal availability has been assessed based on assumed coal stockpiles, domestic coal purchases and foreign coal imports.

The thermal derating methodology and assumptions used are aligned to ensure consistency with our Electricity Risk Curves.

Gas and coal availability - Low Gas Supply sensitivity

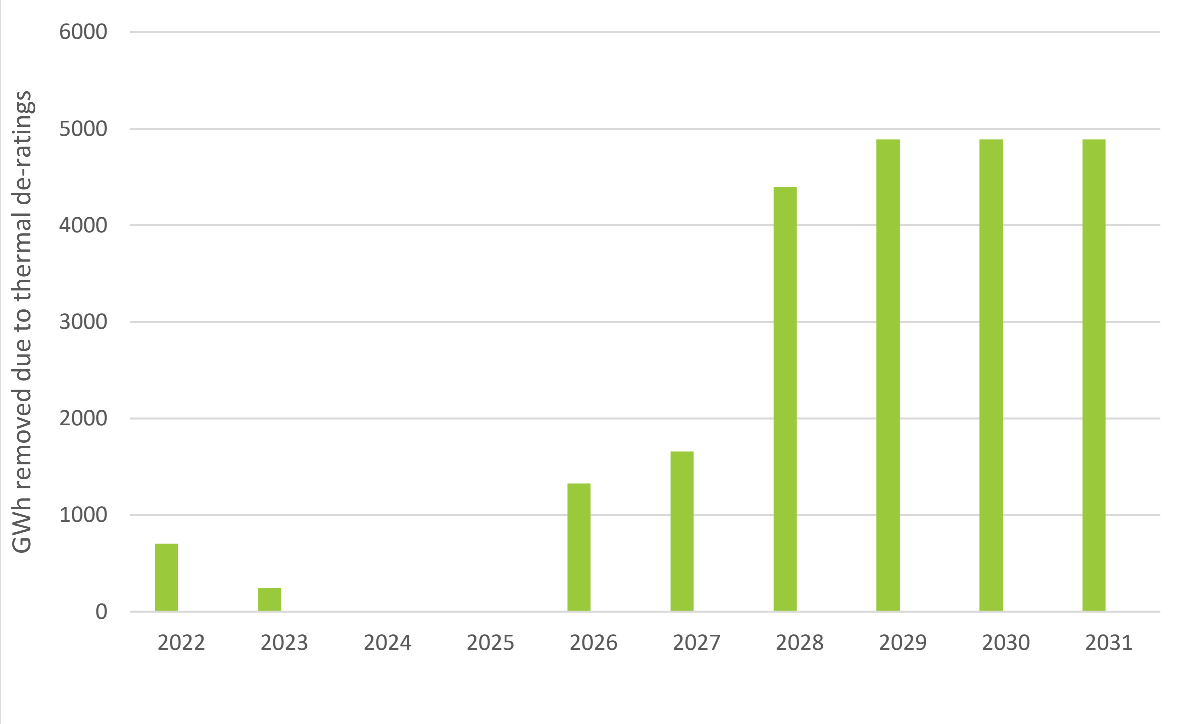
The low gas supply sensitivity assumes less gas is available for electricity generation. In terms of gas supply, in this sensitivity we have followed the same methodology as the gas supply assumptions in the reference case but with gas supply, post 2025, limited at estimated 1P[34] reserves. Under this reduced gas assumption, domestic gas production declines substantially from current levels from 2026. In addition to reduced gas supply, in this sensitivity we also assume less gas demand reallocation occurs from industrial gas users when needed for increased electricity generation. For simplicity, our analysis does not adjust for possible changes to available gas storage associated with a low gas supply future.

Dry year gas supply margins for the low gas supply sensitivity indicate that gas supply will be constrained in the near term (2022 and 2023) due primarily to less gas demand response from industrial users and from 2026 due to less gas demand response in combination with reduced forecast gas supply. From 2027 there will be insufficient gas resulting in constrained operation of existing gas base load and peaking generation. We have assumed that gas cogeneration remains at current levels. It is possible generation from this type of plant could also be constrained towards the end of the 2020s. This will largely depend on how a dwindling supply of gas is allocated to existing industrial gas users, which is beyond the scope of this assessment to consider.

Gas-fuelled generation for winter energy contribution are de-rated due to the low gas supply sensitivity. These deratings are applied to gas-fuelled generators in order of decreasing efficiency (less efficient plant derated before more efficient plant). The derating is shown in Figure 15 as a total energy impact on gas-fuelled generation.

[34] This represents gas supply that has a high probability of being technically and commercially available and is sometimes referred to as 'proven' reserves.

Figure 15: Winter energy gas-fuelled generation deratings - low gas supply sensitivity



We further assume limited gas availability for electricity generation will eventually be so severe that, from 2029 onwards, gas generators will be unable to meaningfully contribute to meeting winter peak demand. This results in thermal generation winter peak contributions being de-rated by ~1100 MW from 2029 due to limited gas availability.

Diesel availability

Consistent with our Electricity Risk Curves, Whirinaki's winter energy contribution is limited to 60 GWh, reflective of fuel delivery logistics.

4.2.6 Inter-Island Transmission Assumptions

North Island energy supply can meet some of the South Island's energy demand in the assessment of the SI-WEM. 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[35].

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

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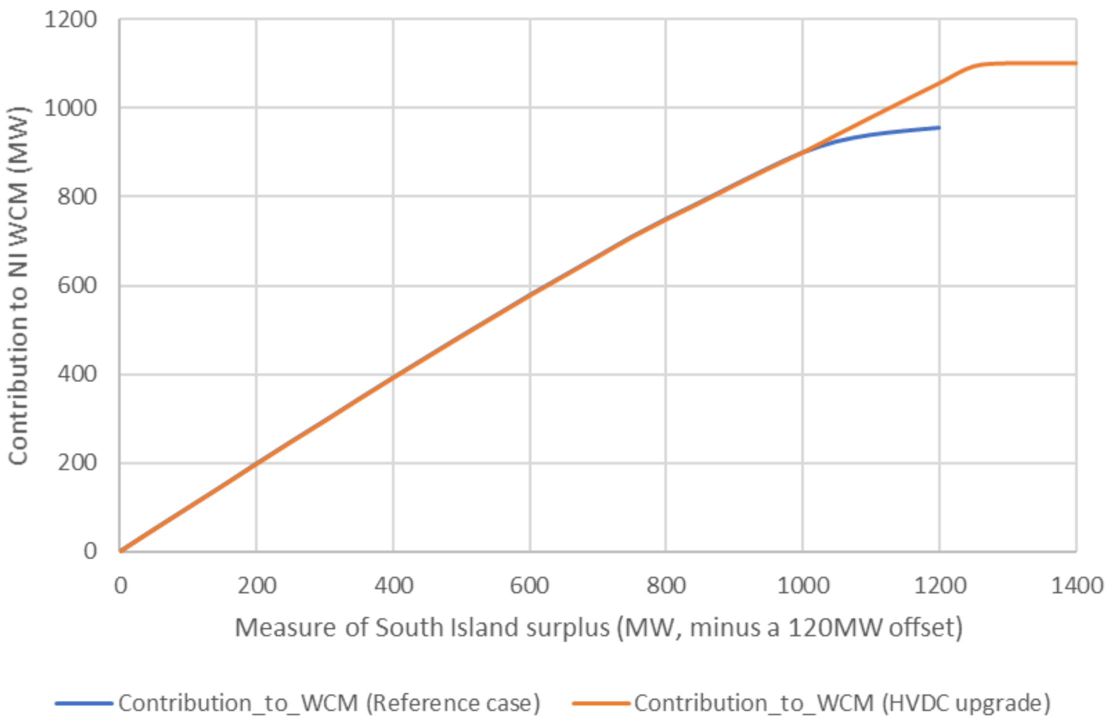
[35] Energy surplus in the North Island is calculated by subtracting North Island demand from available North Island supply.

We consider a sensitivity with an HVDC upgrade which allows a greater proportion of South Island generation to contribute to the NI-WCM. The estimated increase in the contribution of South Island generation to the NI-WCM is shown in Figure 16. The maximum contribution to the NI-WCM with the HVDC upgrade is estimated to be 1103 MW[36].

Figure 16: SI contribution to NI winter capacity margin for reference and HVDC upgrade sensitivity



[36] The maximum contribution with the HVDC upgrade is based on the estimated maximum received power on a single pole (after accounting for losses) plus 400MW (to account for estimated NI reserves required to cover the largest NI risk). This is based on an expected overload capability of 760 MW (sent), (~703 MW received) on pole 2 following the HVDC fourth cable upgrade. At the time of preparing this report, this is one of the long-list options being considered for the potential HVDC upgrade, as discussed here (Long list report transpower.co.nz). As potential HVDC upgrade options are short-listed going forward, in future year's SOSA's we will update this sensitivity's assumptions accordingly and if an upgrade option is confirmed, it will be included in our reference case.

5.0 Results

5.1 Overview and Summary

In this section we present our assessment results, starting with an overview and summary.

For the NZ-WEM, the reference case drops below the upper security standard from 2028 when utilising only the existing and committed supply projects. The addition of all consented and on hold supply projects results in the NZ-WEM, for the reference case, being maintained above the upper security standard through to the end of the 10-year assessment horizon.

For the NI-WCM, the reference case drops below the upper security standard from 2025 when utilising only the existing and committed supply projects. With the addition of all consented and on hold supply projects an adequate NI-WCM can be maintained through to 2028. Capacity from projects likely to seek consent within the next two years will need to be commissioned by winter 2029 in order to maintain an adequate NI-WCM through to the end of the 10-year assessment horizon for the reference case.

For the SI-WEM, the reference case drops below the upper security standard from 2030 when utilising only the existing and committed supply projects. With the addition of all consented and on hold supply projects the SI-WEM remains above the lower security standard through to the end of the 10-year assessment horizon.

Our analysis has identified several individual sensitivities that when applied to the reference case cause the capacity and energy margins to fall below the security standards at an accelerated rate. These sensitivities include but are not limited to demand step changes, high demand growth, low gas supply, thermal generation exits and thermal constraints. If any of these sensitivities were to occur then the need for the development of new supply projects would be increased in order to maintain the security standards.

With the increase in demand being forecast and the changed assumptions since 2021 regarding both Tiwai and TCC remaining, a large number of sensitivity combinations fall below the capacity (NI-WCM) and energy (NZ-WEM) security standards by 2024 and 2026 respectively (especially for Stage 1[37]).

For all supply pipeline stages, the years up to 2028 are susceptible to sensitivities that:

1. increase demand growth from the reference case, such as high demand or step increase in demand;
2. decrease in supply of existing generation from the reference case, such as early retirement of generation, reduced operation or low thermal fuel supply; and/or
3. reduce the supply pipeline such as gas consents being left undeveloped.

While this risk could reduce after 2028 for Stage 4, there higher level of uncertainty associated with the large number of supply projects that are not consented but where consent is expected and likely to be sought in the next two years.

[37] Supply pipeline Stage 1 includes only existing and committed projects.

While these sensitivities impact all margins analysed, they have a particularly acute impact on the NI-WCM.

5.2 Winter Energy Margin Results

5.2.1 New Zealand Winter Energy Margin Reference Case Results

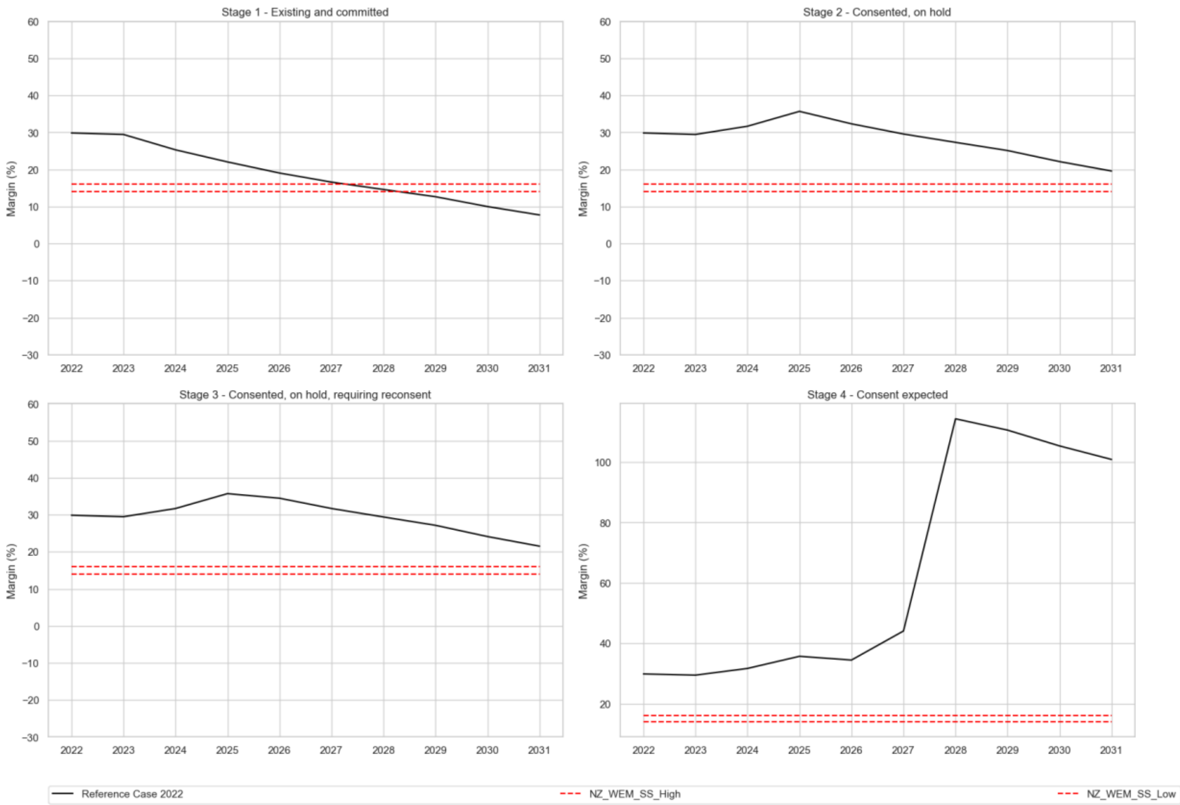
The NZ-WEM results for the reference case are shown in Figure 17. This illustrates that:

1. with existing and committed generation (Stage 1) the NZ-WEM declines and crosses the upper security standard in 2028;

2. for the reference case to maintain the NZ-WEM above the upper security standard throughout the assessment horizon then in addition to the existing and committed generation, most of the consented and on hold supply projects would need to be developed (Stages 2 or 3); and

3. from 2027 and 2028 a large amount of generation that is currently expecting to seek consent within the next two years could begin to come online. This pool of resources, while large does have a higher degree of uncertainty, but due to its renewable nature is not reliant on thermal fuel development as some existing consents are.

Figure 17 NZ winter energy margin reference case results



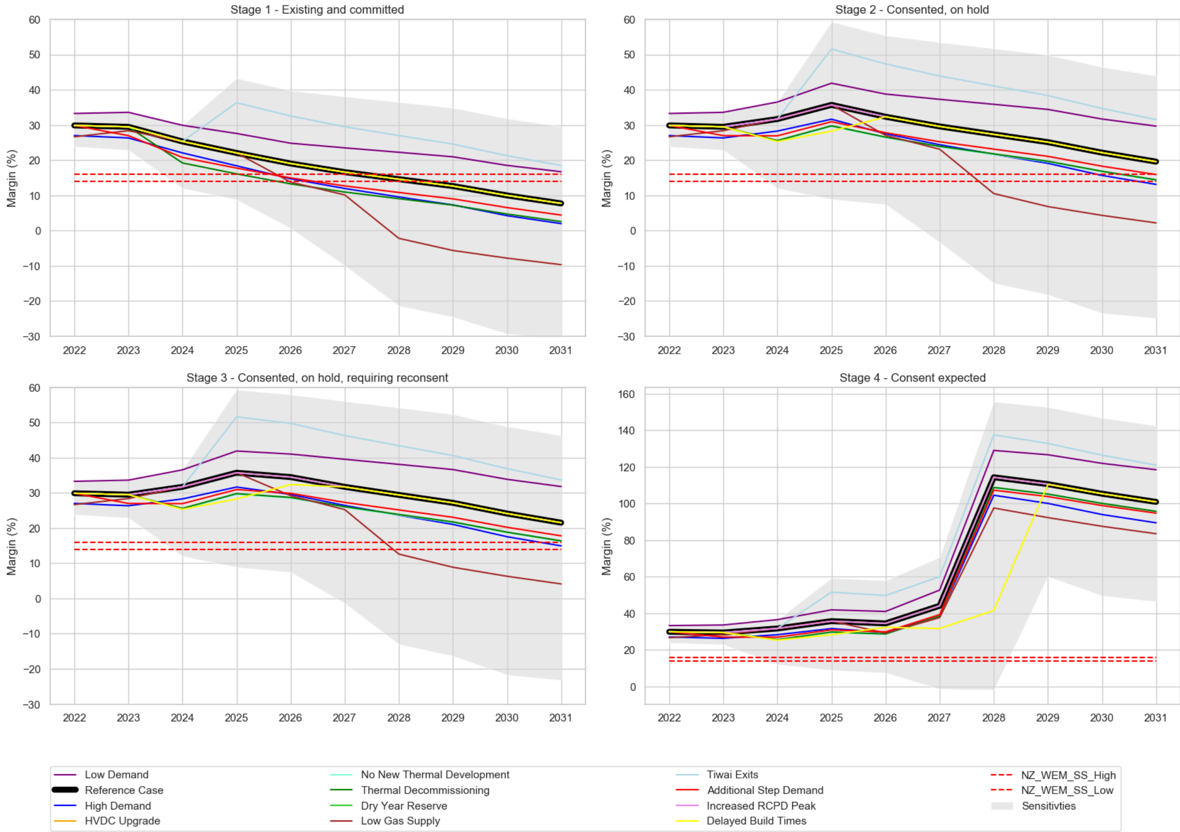
In the 2021 SOSA, there was a significant upward step change in the NZ-WEM from 2025, as a result of Tiwai closure. However, in this year's SOSA our reference case assumes Tiwai will be remaining through to the end of the 10-year assessment period, as reflected by recent Rio Tinto announcements. Tiwai closing at the end of 2024 is treated as a sensitivity.

5.2.2 New Zealand Winter Energy Margin Sensitivities

In this section we present the impact the sensitivities have on the reference case and whether these impacts accelerate or delay the NZ-WEM crossing the upper security standard. Additional, graphical representation for all sensitivity combinations are provided in Appendix 5.

Figure 18 shows the impact of each of the sensitivities when applied independently to the reference case for each of the four potential supply pipeline stages. Applying each sensitivity independently from one another allows us to observe the magnitude of each sensitivity's impact on the NZ-WEM (relative to the reference case).

Figure 18: NZ winter energy margins for the reference and all sensitivities independent of one another



From Figure 18 we have determined that the sensitivities that have the greatest impact on the NZ-WEM are Tiwai exits, additional step demand, high and low demand growth and low gas supply. Additional analysis for these sensitivities can be found below.

Tiwai Exits

Figure 18 shows the impact of Tiwai leaving in 2025, where national energy demand is assumed to decrease by approximately 400 GWh every month from 2025. This is observed in Figure 18 by a noticeable increase in NZ-WEM from 2025 onwards, compared with the reference case. The general trend from 2025 onwards aligns with the reference case. For all potential supply pipeline stages, the Tiwai exits sensitivity does not cross the upper security standard.

Figure 19 shows the result of all possible sensitivity combinations with Tiwai remaining (grey lines) and Tiwai exiting (blue lines). For Stage 1, when Tiwai exits, some combinations of sensitivities cross the upper security standard briefly in 2024, these are:

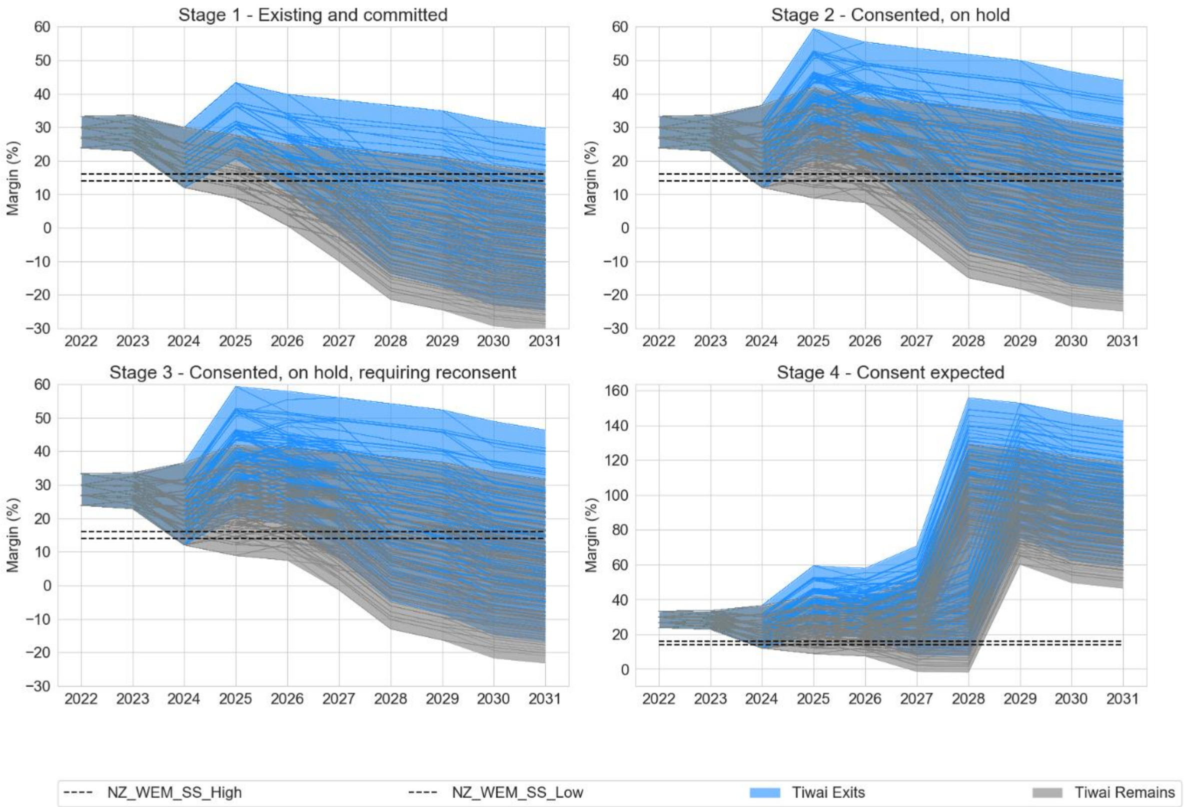
a) high demand either as a step change in demand or higher growth rates; and

b) early retirement of fossil-fuelled thermal generation (such as thermal decommissioning), and constrained thermal development.

However, most sensitivity combinations cross from 2027 onwards. When Tiwai remains, this is brought forward with most sensitivity combinations crossing the upper security standard from 2026 onwards.

Stages 2-4 show a similar pattern observed in Stage 1 with a positive shift to the NZ-WEM from 2025 onwards. For Stages 1-3, the sensitivity combinations where Tiwai exits, the upper security standard is still crossed by a significant number of combinations from 2027.

Figure 19: All sensitivity combinations containing Tiwai exits for all four supply pipeline stages



Demand Step Change

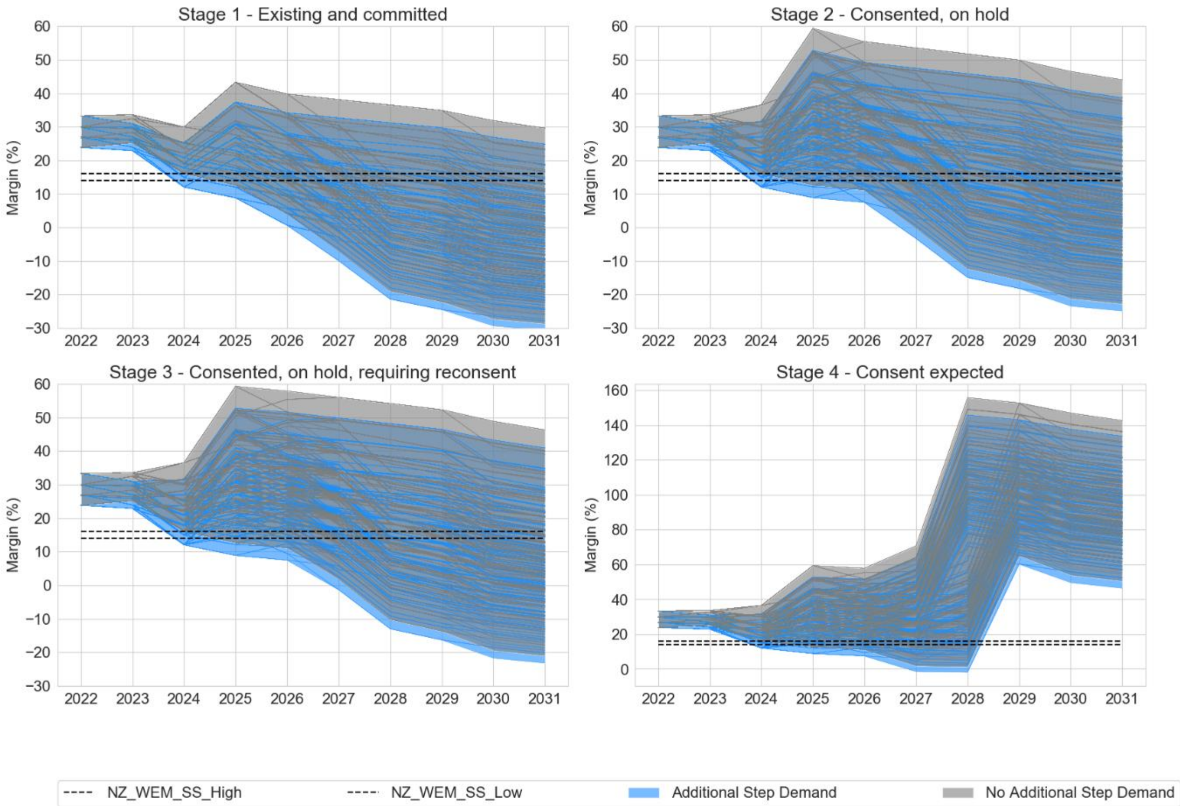
Figure 18 shows the impact of the demand step change sensitivity, where national energy demand is assumed to increase by 100 MW in the South Island from 2023 and 100 MW in the North Island from 2024. This is observed in Figure 18 by a decrease in the NZ-WEM from 2024 onwards, compared with the reference case. The general trend in the NZ-WEM from 2024 onwards aligns with the reference case.

Figure 20 shows the result of all possible sensitivity combinations with demand step changes (blue lines) and no demand step changes (grey lines). For Stage 1, with demand step changes, some combinations of sensitivities cross the upper security standard from 2024, however most combinations cross from 2026 onwards. With no demand step changes, there is a year delay with most sensitivity combinations crossing the upper security standard in 2027.

Stages 2-4 show a similar pattern to that observed in Stage 1 with a positive shift to the NZ-WEM from 2024 onwards due to the inclusion of consented generation. This pushes out the period where majority of the sensitivities remain above the margin for another 1-2 years.

Development of some of the unconsented generation pipeline from 2028 is needed to maintain the NZ-WEM to the end of the assessment horizon for the combination of sensitivities (with or without the additional step demand).

Figure 20: All sensitivity combinations containing demand step changes for all potential supply pipeline stages



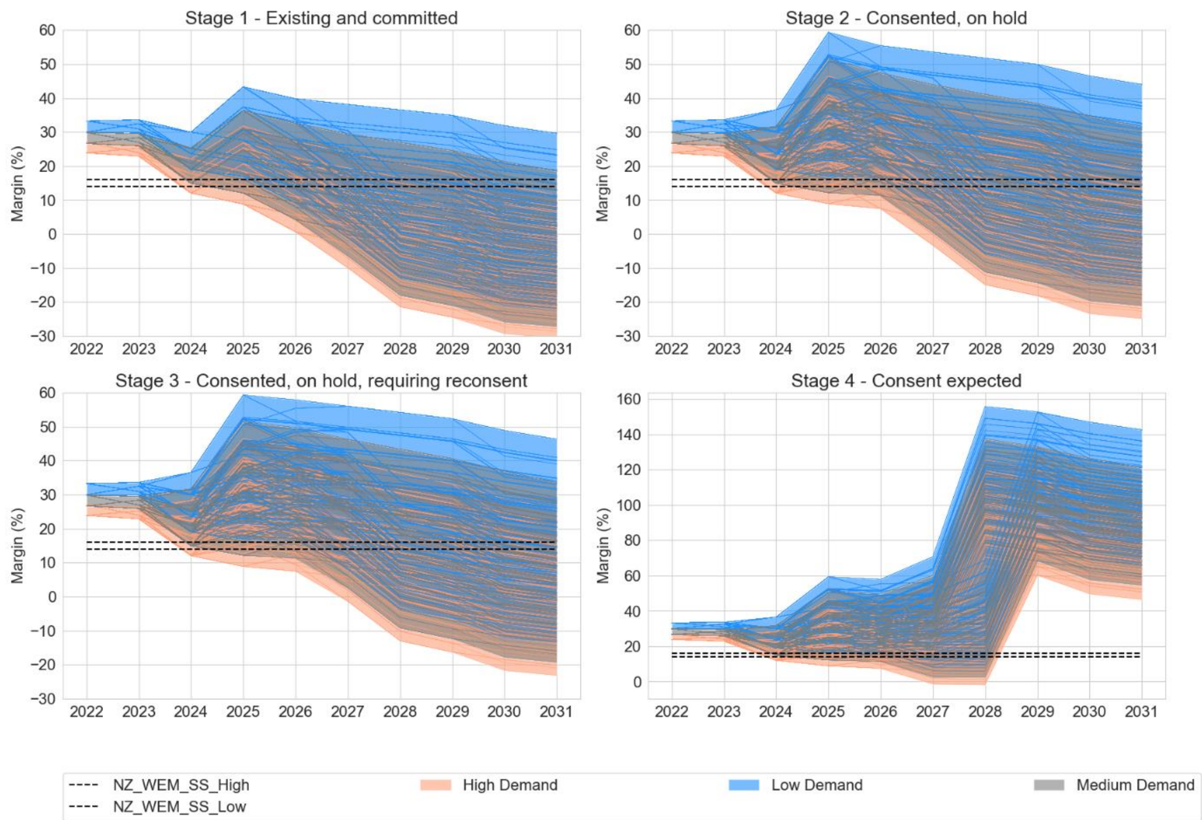
Demand Growth

Figure 18 shows the impact of both the low and high demand growth sensitivities, where the demand growth rates occur at a lesser or greater rate than the reference case's medium demand growth rate.

From Stage 1 in Figure 18, we can see that the low demand growth rate sensitivity does not cross the upper security standard during the assessment horizon. Stages 2-4 illustrate a similar pattern as that observed in Stage 1 for the low demand growth scenario with the NZ-WEM for the low demand growth sensitivity only remaining above the security standard.

Figure 21 shows the result of all possible sensitivity combinations with high (red lines), medium (grey lines) and low demand growth (blue lines). In Figure 21 for Stage 1, if the demand growth is low, sensitivity combinations begin crossing the upper security standard from 2025 with most combinations crossing from 2027 onwards. When the demand growth isn't low, most sensitivity combinations cross the upper security standards in 2026 with some sensitivity combinations crossing as early as 2023. These combinations are related to high demand growth combining with reduced supply of the existing generation.

Figure 21: All sensitivity combinations containing low, medium and high demand growth



From Stage 1 in Figure 18 we can see that a high demand growth rate crosses the upper security standard from 2026 which is two years sooner than in the reference case. Stages 2-4 show a similar pattern observed in Stage 1. In Stages 2 and 3, the high demand sensitivity crosses the upper security standard two years earlier than the reference case.

For both Stages 2 and 3 the vast majority of sensitivity combinations with a high demand growth rate fall below the upper security standard before the end of the 10-year assessment horizon. This indicates that to maintain the NZ-WEM if demand is higher than forecast, all existing generation will be needed to not retire early, and ongoing investment in fossil-fuelled thermal generation and thermal fuels will be required to bridge the gap to 2027 when more currently unconsented renewable generation is expected to be developed. This is shown further in Stage 4.

Under Stage 4, a large number of sensitivity combinations with high demand growth rates drop below the upper security standard by 2024. However, all sensitivity combinations return to above the security standards from 2028 and remain above for the remainder of the 10-year assessment horizon. This increase in NZ-WEM post 2028 is due to the potential future unconsented generation. This implies that if there is an extended period of high demand growth, then development of currently unconsented projects will need to come forward to maintain the security standards.

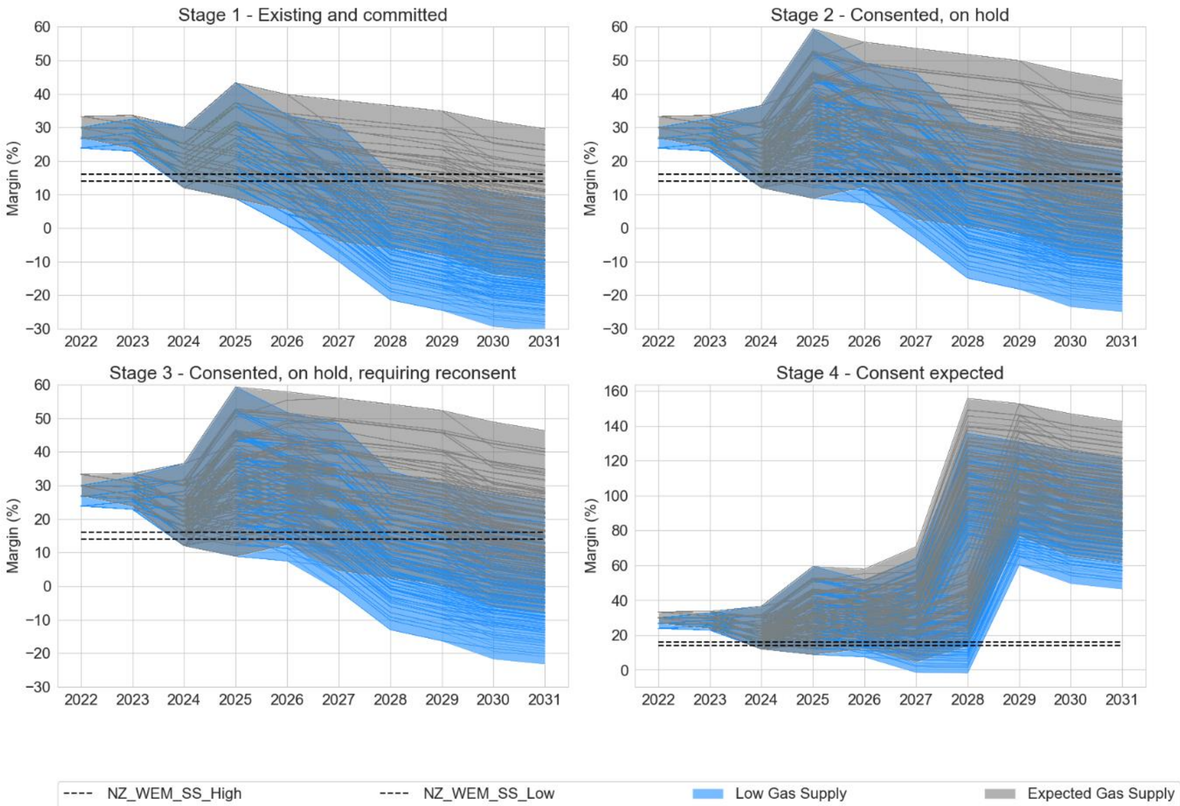
Low Gas Supply

Figure 18 shows the impact of the low gas sensitivity, which is a decline in gas available for electricity generation reducing the NZ-WEM from 2026 onwards due to the reduced supply. This is intended to demonstrate the worst-case scenario for domestic gas production over the coming decade combined with a reduction in the gas reallocated from industrial gas users to electricity generation during dry years thus reducing gas available for electricity generation. It also has the similar impact as gas consents being left undeveloped.

Figure 22 shows the result of all possible sensitivity combinations with low gas supply (blue lines) and expected gas supply (grey lines). For Stage 1, with low gas supply, some combinations of sensitivities cross the upper security standard from 2024, however most combinations cross from 2026 onwards. With sufficient gas supply, there is a delay with most sensitivity combinations crossing the upper security standard slightly later in 2028.

Stages 2-4 show a similar pattern observed in Stage 1 but with a positive shift to the margins from 2024 onwards.

Figure 22: All sensitivity combinations containing low gas supply for all potential supply pipeline stages



5.2.3 South Island Winter Energy Margin Results

SI-WEM is comparatively much higher than the NZ-WEM. The SI-WEM result for the reference case is shown in Figure 23. This shows the SI-WEM will cross the lower security standard in 2030 for Stage 1. For Stages 2-4 the SI-WEM doesn't cross the lower security standard the 10-year assessment horizon.

Figure 23: SI winter energy margin reference case results

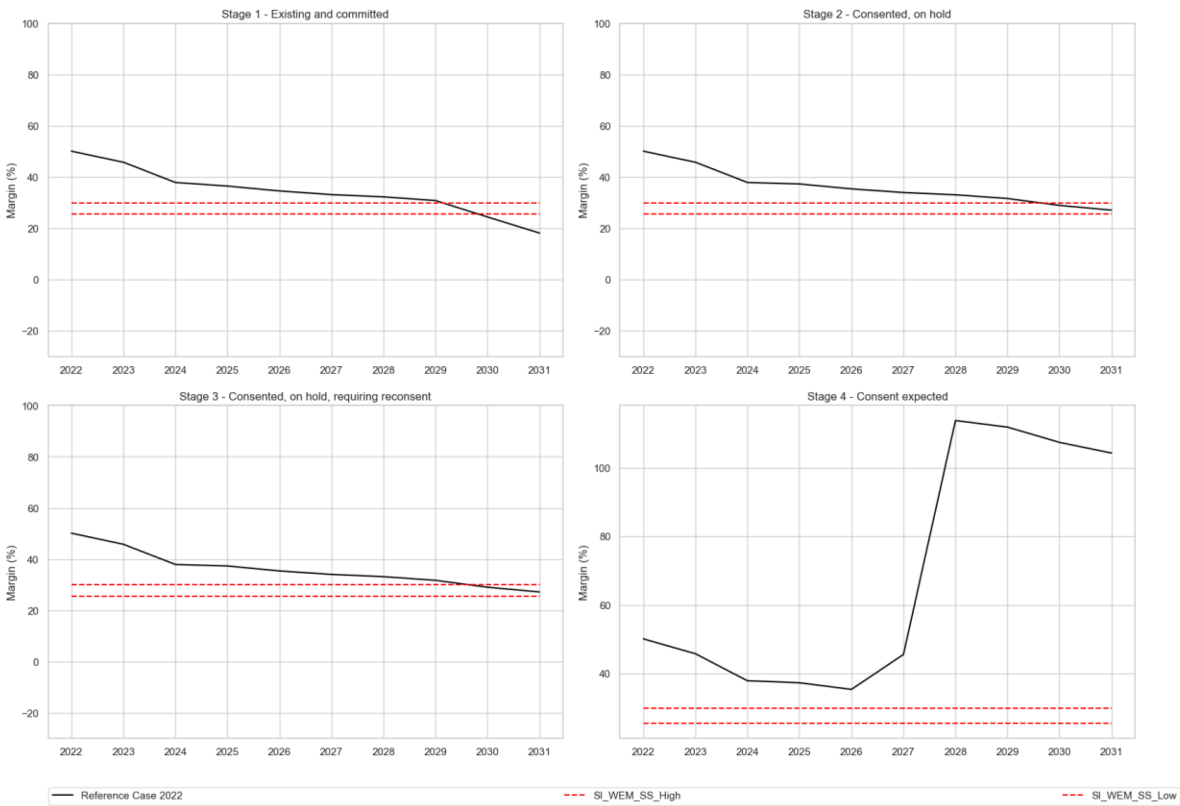
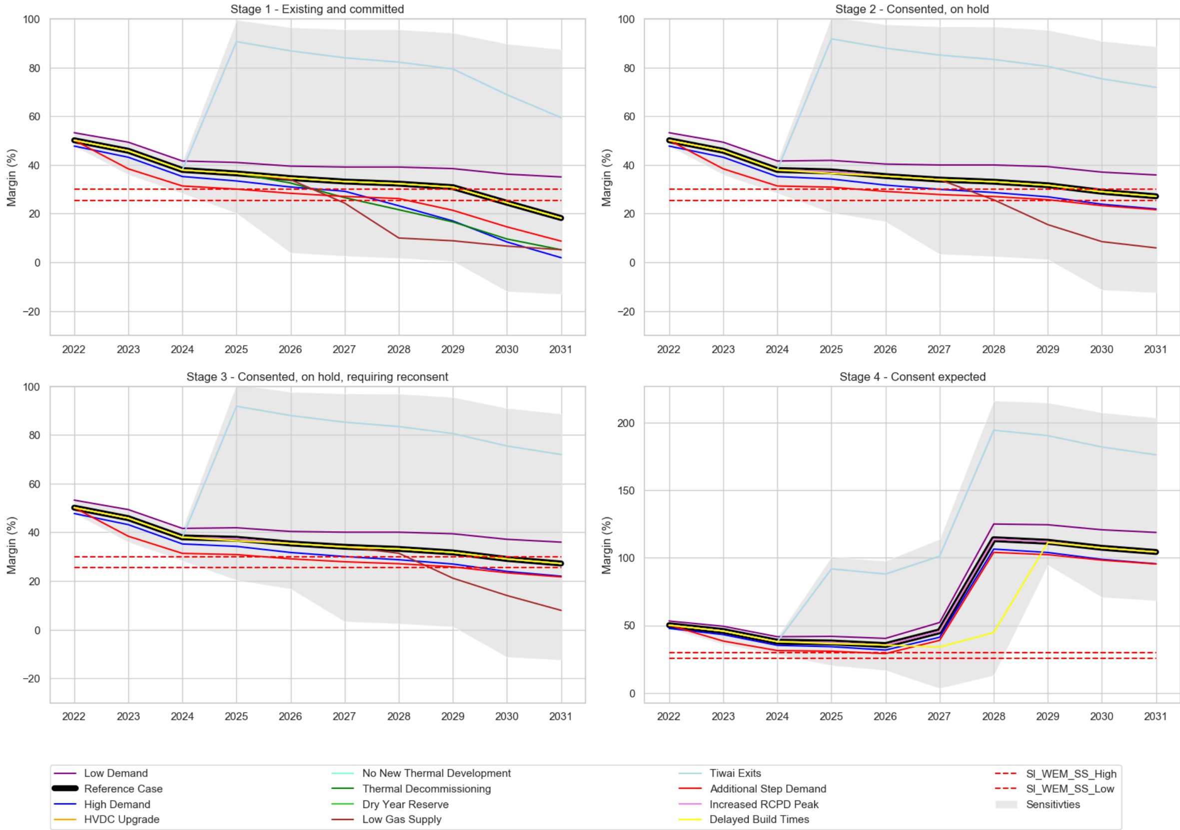


Figure 24 shows the impact each of the sensitivities have on the reference case and whether these impacts speed up or delay the SI-WEM crossing the lower security margin. Each of the sensitivities has been applied independently from one another so the magnitude of the impacts for each sensitivity can be compared to one another.

Figure 24: South Island winter energy margin sensitivity results



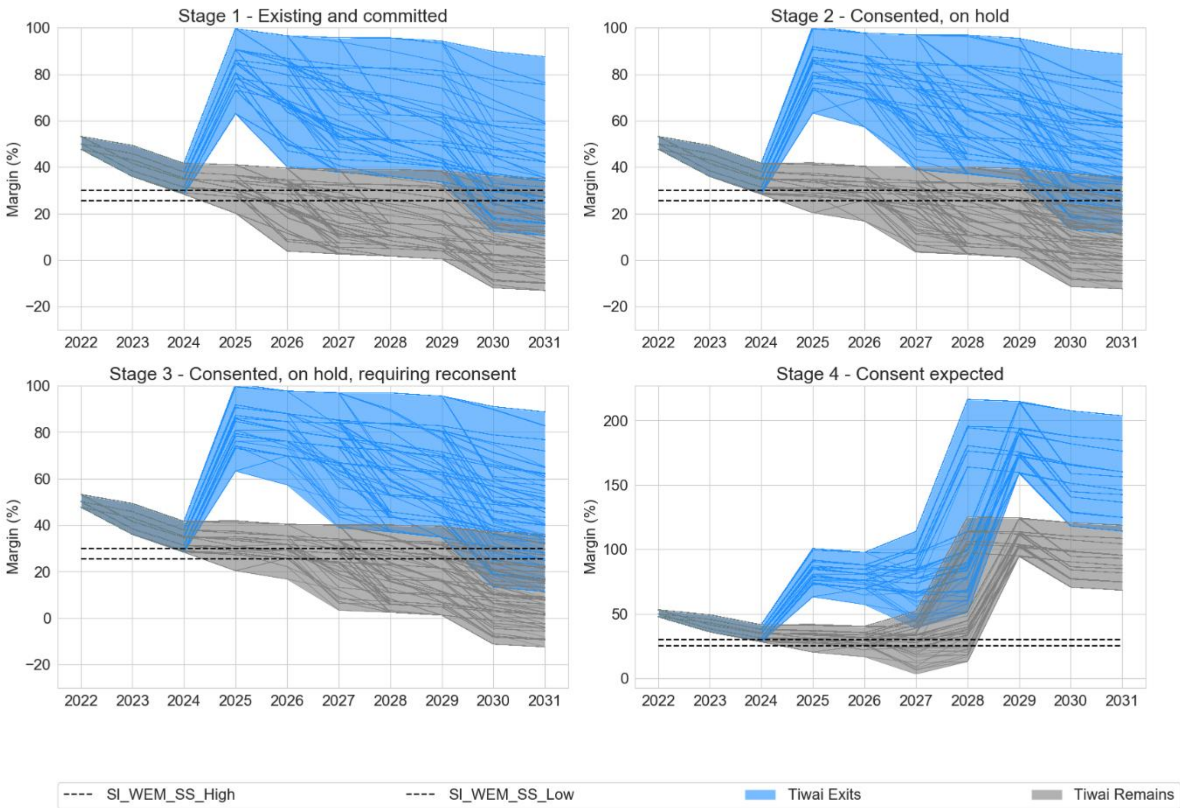
If only existing and committed generation was available, there is a risk that a high demand growth[38], demand step change, early retirement of fossil-fuelled thermal generation[39], and low gas supply sensitivities could cause the lower security margin to be crossed from as early as 2025. However, if Tiwai exits under any of the potential supply pipeline stages the risk of the SI-WEM crossing the lower security standard is almost completely mitigated.

[38] Higher than the medium demand growth we used for the reference case.
[39] This is modelled as TCC exits.

Tiwai Exits

The Tiwai exits sensitivity shows a significant increase in the SI-WEM from 2025 onwards. This shift in the margins means that no sensitivity combination with Tiwai leaving crosses the lower security standard before 2029. There is minimal overlap between the combination of sensitivities with Tiwai remaining and Tiwai leaving. If Tiwai remains, the lower security standards can be crossed from as early as 2024 if only considering existing and committed generation.

Figure 25: All sensitivity combinations containing Tiwai exits for all potential supply pipeline stages



5.3 Winter Capacity Margin Results

5.3.1 North Island Winter Capacity Margin Scenario Results

The NI-WCM result for the reference case is shown in Figure 26 below. From this we can see that for Stage 1, the NI-WCM will cross the upper security standard from 2025.

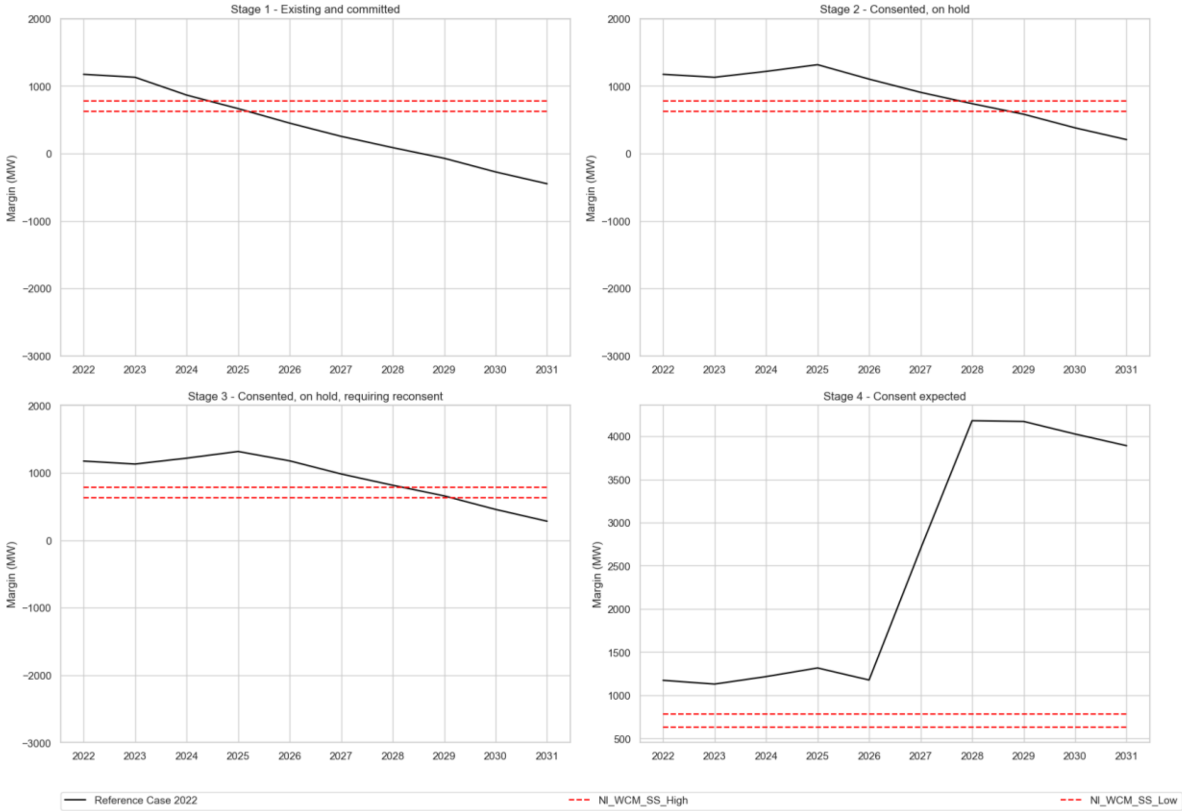
The NI-WCM results for the reference case are shown in Figure 26. This illustrates that:

1. with existing and committed generation (Stage 1) the NI-WCM declines and crosses the upper security standard from 2025;

2. the addition of consented and on hold projects (Stages 2 and 3) helps maintain the NI-WCM above the upper security standard through to around 2028; and

3. additional unconsented projects (Stage 4) would be needed to maintain the NI-WCM beyond 2028 for the remainder of the assessment horizon. As noted previously, this pool of currently unconsented resources, while large does have a higher degree of uncertainty, but due to its renewable nature is not reliant on thermal fuel development as some existing consents are.

Figure 26 North Island winter capacity margin reference case result



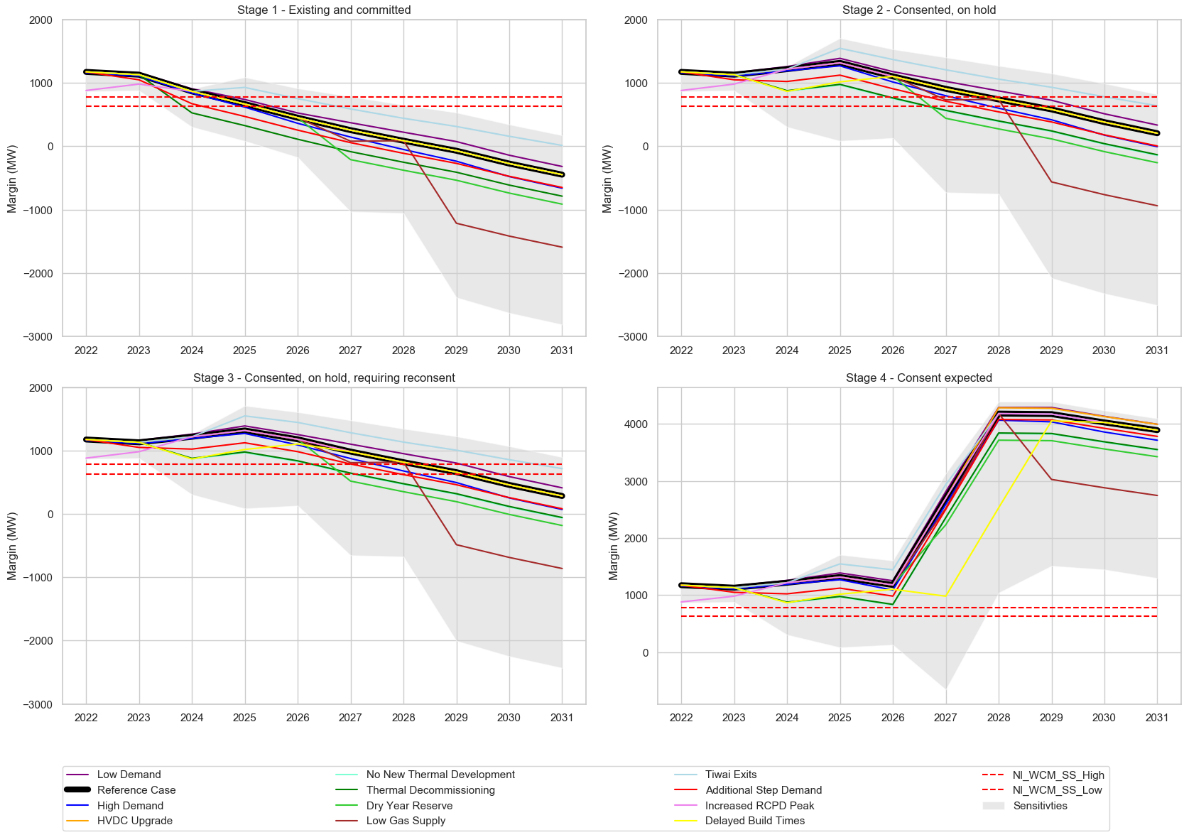
5.3.2 North Island Winter Capacity Margin Sensitivities

In this section we present the impact that sensitivities have on the reference case and whether these impacts accelerate or delay the NI-WCM crossing the upper security standard. Additional, graphical representation for sensitivity combinations are shown in Appendix 5.

Figure 27 shows the impact of each of the sensitivities when applied independently to the reference case for each of the four potential supply pipeline stages. Applying each sensitivity independently from one another allows us to observe the magnitude of each sensitivity's impact on the NI-WCM (relative to the reference case).

From this we have determined the sensitivities that have the greatest impact on the NI-WCM are Tiwai exit, thermal decommissioning, constrained thermal development, dry year reserve and low gas supply. Additional analysis for these sensitivities can be found below.

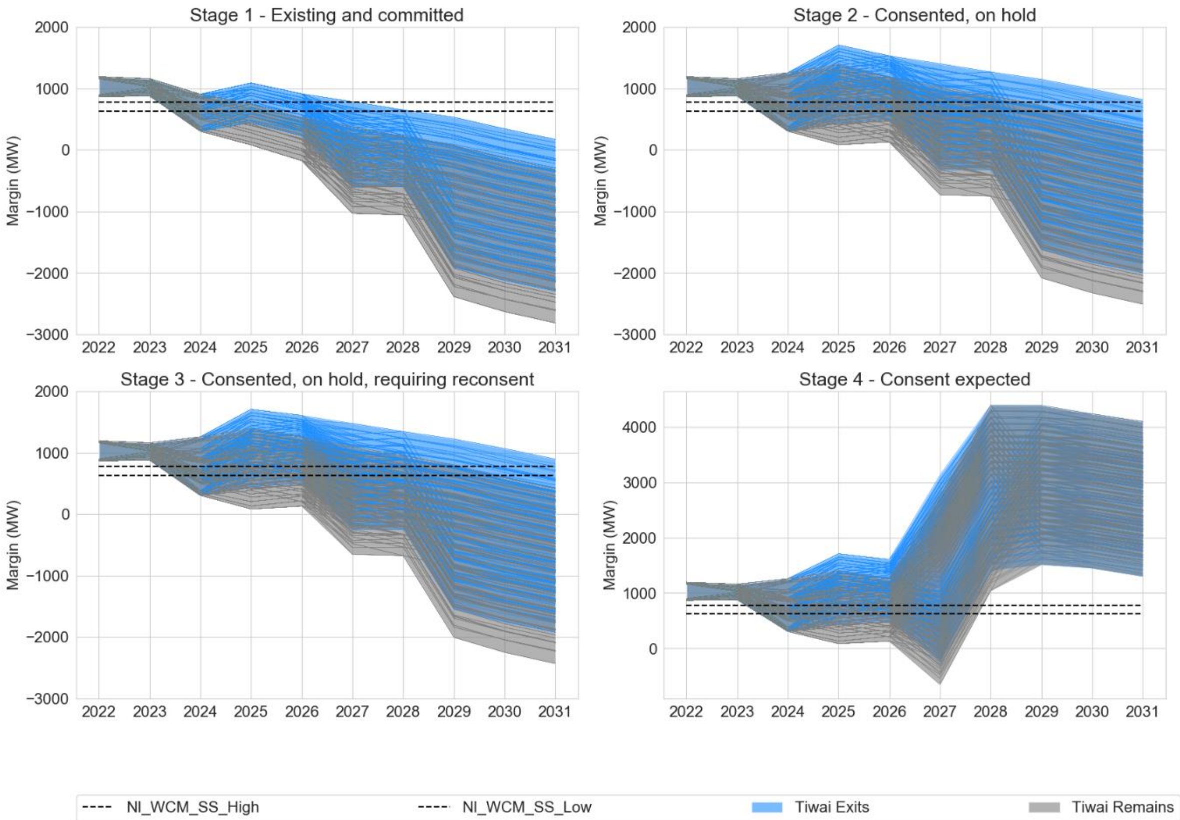
Figure 27: NI winter capacity margins for the reference and all sensitivities



Tiwai Exits

Tiwai closing has the effect of increasing the NI-WCM relative to the reference case as seen in Figure 27. This is due to the additional surplus SI generation that can contribute to supplying the NI peak demand. In Figure 28 under Stage 1, which only considers existing and committed generation, Tiwai leaving delays the timing of when the NI-WCM drops below the security standard however at the end of the assessment horizon, both the Tiwai leaving and Tiwai remaining states with the combinations of sensitivities are below the NI-WCM security standard. However, when also considering consented and unconsented generation (Stages 2-4), the proportion of sensitivity combinations above the upper security standard across the 10-year assessment horizon becomes more dependent on whether Tiwai remains or leaves. For Stages 1-4, combinations of sensitivities for both Tiwai leaving and remaining can start crossing the upper security standard from 2024. However, whereas under Stage 1 the NI-WCM for the different sensitivity combinations decline further below the security standard, irrespective of whether Tiwai were to exit or remain, new consented and unconsented projects (included in Stages 2-4) provide some increase in the NI-WCM resulting in a greater proportion of sensitivity combinations remaining above the security standard with Tiwai leaving compared to Tiwai remaining.

Figure 28: All sensitivity combinations containing Tiwai exits for all potential supply pipeline stages



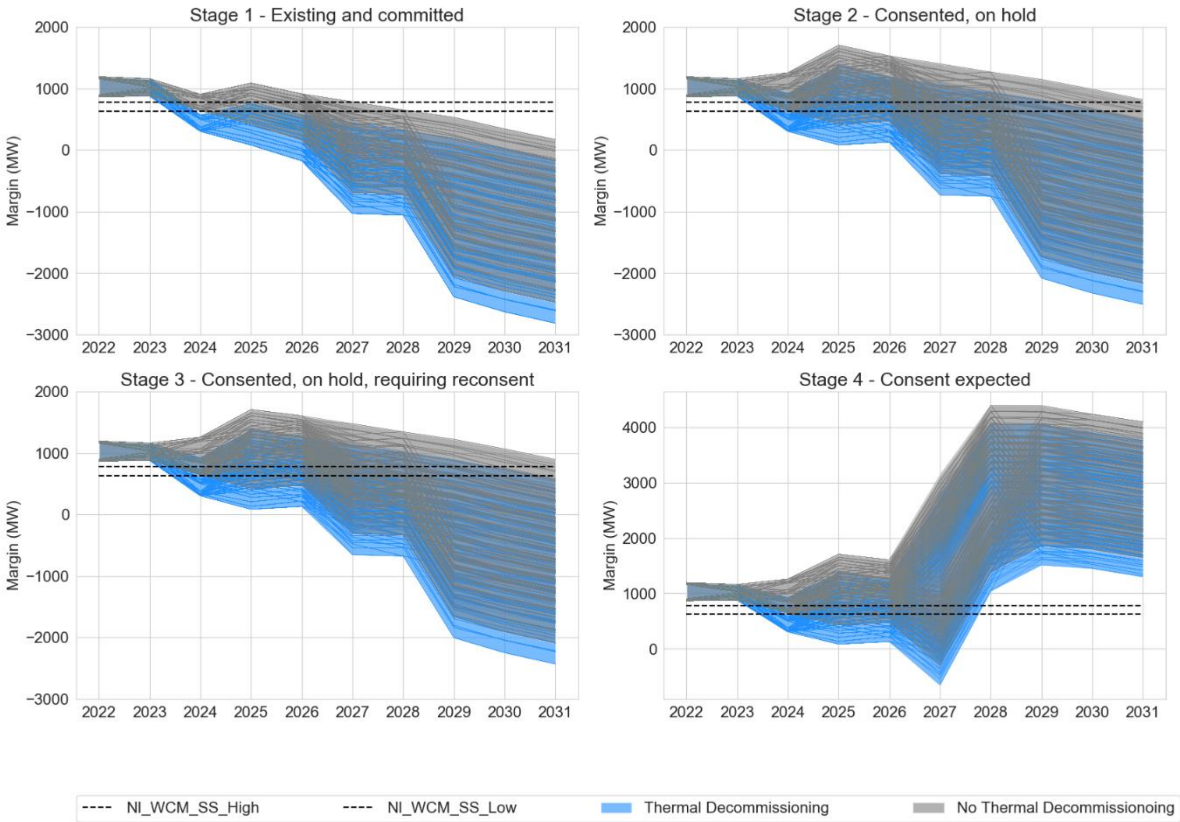
Thermal Decommissioning

Figure 27 shows the impact of considering the near-term decommissioning of a significant fossil-fuel generation asset (modelled as TCC exit[40]). This is observed in Figure 27 by a decrease in the NI-WCM from 2024 onwards, compared with the reference case. The general trend from 2024 onwards aligns with the reference case for all four potential supply pipeline stages.

Figure 29 shows the result of all possible sensitivity combinations with thermal decommissioning (blue lines) and no thermal decommissioning (grey lines). For Stage 1, with TCC out of the market, all combinations of sensitivities cross the upper security standard in 2024. None of these sensitivities rise above the upper security standard throughout the remainder of the 10-year assessment horizon. For Stages 2 and 3, a significant number of the sensitivity combinations fall below the upper security standards in 2024, with most combinations crossing from around 2026 onwards. With TCC remaining, there is a slight delay with most sensitivity combinations crossing the upper security standard around 2027. This illustrates that if there is a thermal decommissioning in the near-term (e.g. TCC exits), unconsented projects will need to be developed to maintain adequate NI-WCM.

[40] This represents a 360MW fossil-fuelled thermal generation decommissioning.

Figure 29: All sensitivity combinations for thermal decommissioning for all potential supply pipeline stages



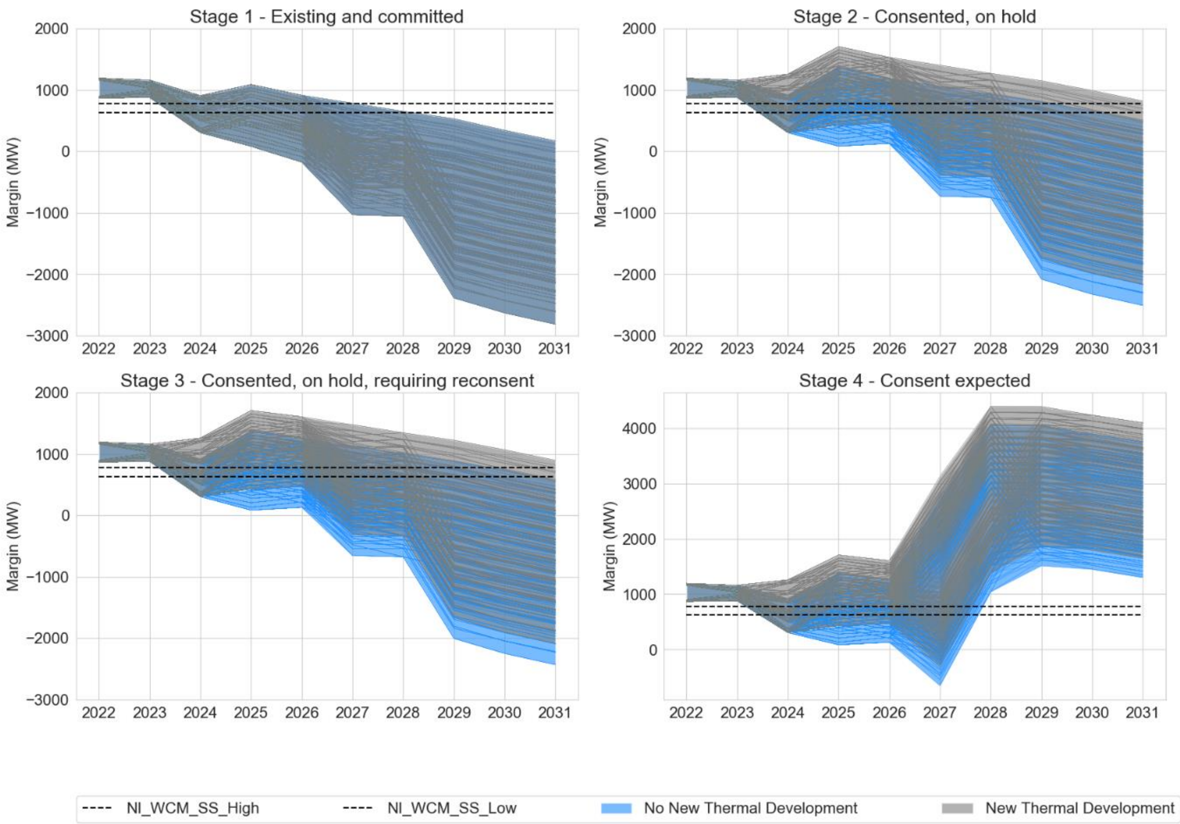
No New Thermal Development

Figure 27 shows the impact of the no new development sensitivity, assuming that no new gas (or other fossil fuel) generation will be built in the future. This is observed in Figure 27 by a decrease in the NI-WCM for Stages 2-4 from 2024 onwards, compared to the reference case. The general trend from 2024 onwards aligns with the reference case for potential supply pipeline Stages 2-4.

Figure 30 shows the result of all possible sensitivity combinations with constrained thermal development (blue lines) and unconstrained thermal development (grey lines). For Stage 1, there is no distinction between the constrained and unconstrained thermal development states as none of the supply projects classed as existing and committed are fossil-fuel generation projects. For Stages 2 and 3, with potential development of fossil-fuel generation, there is a difference between constrained and unconstrained thermal development. For these stages (2 and 3), constrained thermal development in combination with other sensitivities that also reduce the NI-WCM, results in the NI-WCM starting to cross the upper security standard for more sensitivity combinations from 2024 with most sensitivity combinations crossing from around 2027 onwards. With unconstrained thermal development, there is a slight improvement in the NI-WCM with less sensitivity combinations crossing the upper security standard compared to with constrained thermal development.

Development of unconsented projects (Stage 4) shift the range of NI-WCM upwards for the set of sensitivity combinations with and without constrained thermal development. This demonstrates the renewable nature of the unconsented project pipeline.

Figure 30: All sensitivity combinations containing no new thermal development for all potential supply pipeline stages



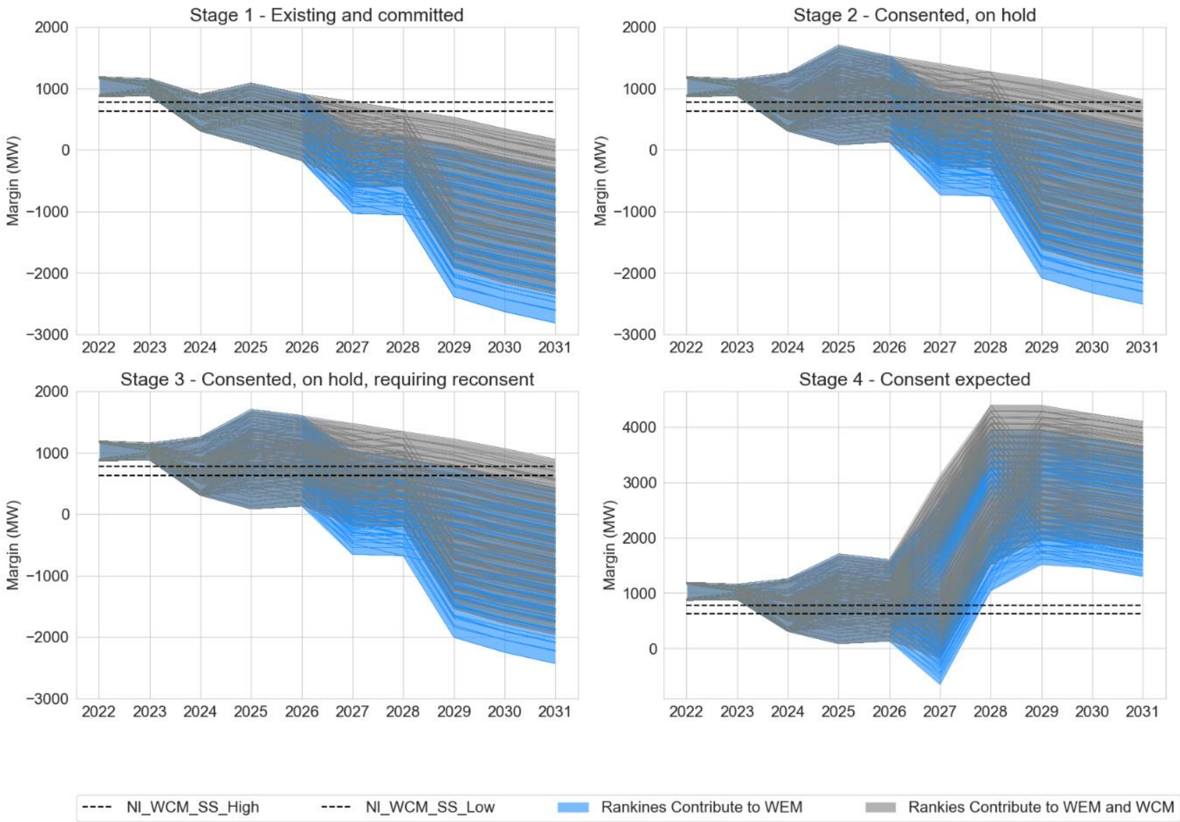
Dry Year Reserve

Figure 27 shows the impact of the dry year reserve sensitivity. This sensitivity tests the impact if 480MW of existing fossil-fuel generation capacity had limited operation and was only used during periods of low hydrology (dry year), but not for short term, unanticipated supply shortages unrelated to low hydrology from 2027 onwards. Therefore, this capacity would contribute to the energy margins, but not the capacity margin. This is observed in Figure 27 by a decrease in the NI-WCM in 2027. In Stage 1, by 2025 the NI-WCM has already crossed the upper and lower security standards. However, for Stages 2-3 the dry year reserve sensitivity speeds up the crossing of the upper security margin from 2029 (in the reference case) to 2027.

Figure 31 shows the result of all sensitivity combinations with dry year reserve only operation (Rankines contribute to the WEM) (blue lines) and without dry year reserve only operation (Rankines contribute to the WEM and WCM) (grey lines). When only considering existing and committed generation (Stage 1), all sensitivity combinations are above the standards in 2023 however start dropping below the standards from 2024. The reduced operation of some thermal generation (to dry year reserve operation) accelerates the decline of the calculated NI-WCM as shown in the blue shaded area dropping below the grey shaded area from 2027.

When also considering consented projects (Stage 2 and C), under dry year reserve only operation, majority of combinations of sensitivities have dropped below the upper security margin from 2027. If the Rankines were also able to contribute to the peak (i.e. not dry year only operation) then the proportion of sensitivity combinations (grey shaded area) that reduce below the capacity security standard reduces. This highlights the need to avoid reducing current operational capacity until this capacity can be replaced. Stage 4 indicates there is potential unconsented projects which if developed can help replace this operational capacity.

Figure 31: All sensitivity combinations with and without dry year reserve only operation for all potential supply pipeline stages

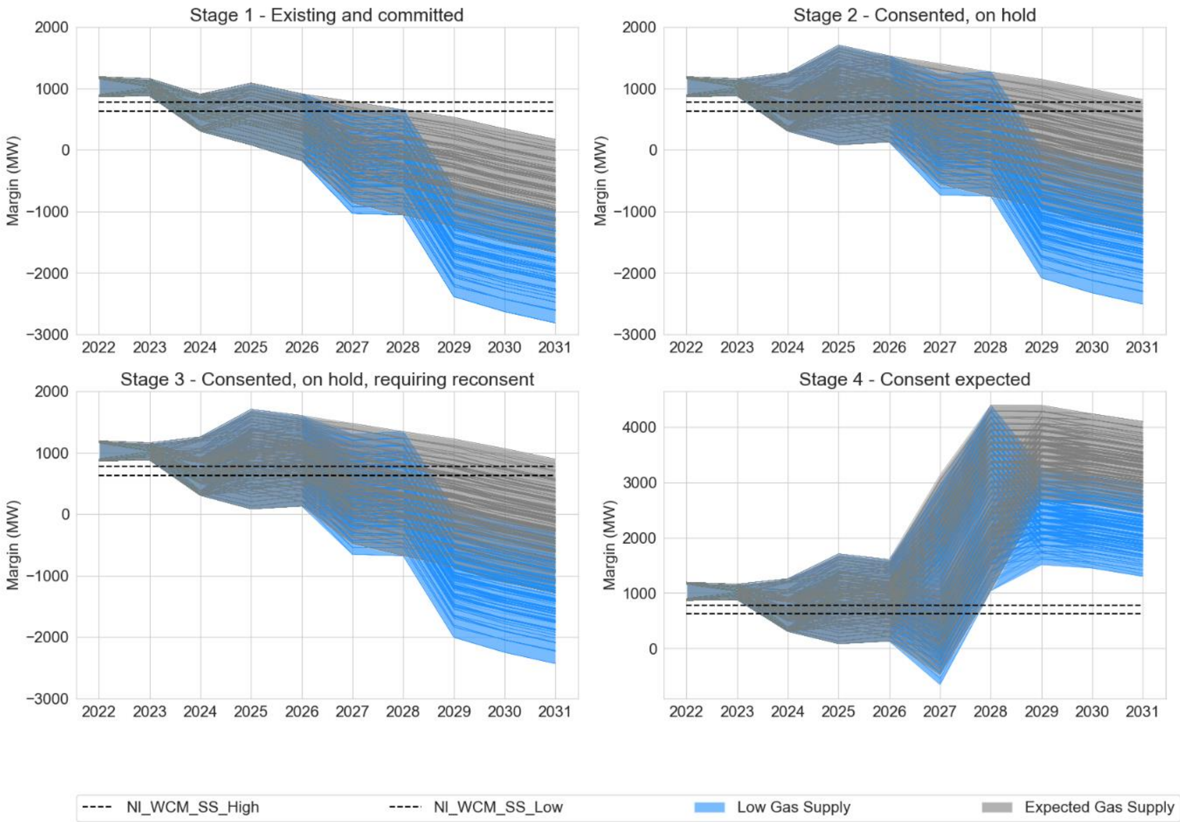


Low Gas Supply

Figure 27 shows the impact of the low gas supply sensitivity, which is a decline in domestic gas production reducing the NI-WCM from 2025 onwards due to the reduced supply. This is intended to demonstrate a severely constrained scenario of gas availability for electricity generation over the 10-year assessment horizon. The application of the low gas supply sensitivity causes the NI-WCM to drop significantly further below the security standards for Stages 1-3 from 2029. Figure 32 shows by this time the NI-WCM for a large proportion of sensitivity combinations (with expected gas supply) are already below the security standard. This is because this sensitivity starts impacting the NI-WCM when the low gas supply starts impacting the generators ability to generate during peak times which only occurs later in the assessment horizon. This indicates that the low gas supply sensitivity tends to impact the energy margins more acutely than the capacity margins.

The development of currently unconsented projects from 2028 can increase the NI-WCM to help mitigate the downside effects of reduced gas availability.

Figure 32: All sensitivity combinations containing low gas supply for all potential supply pipeline stages



5.4 Comparison with the 2021 SOSA

Figure 33, Figure 34 and Figure 35 below shows the NZ-WEM and NI-WCM for the 2022 reference case and the 2021 base case with medium demand (with Tiwai included).

In the first five years of the assessment horizon both the NZ-WEM and NI-WCM in 2022 is lower relative to the 2021 SOSA. This is primarily due to the expectation of stronger demand growth from distributors, with greater electrification driving increased energy and peak demand. This results in the 2022 SOSA showing tighter margins than in 2021 for the first five years of the period being analysed.

The margins in 2022 SOSA largely improve relative to the 2021 SOSA for the following five years (2027 to 2031). This is primarily due to the large pipeline of future, unconsented renewable projects. These improve both the energy and capacity margins relative to the 2021 SOSA. This increased activity in potential new generation and load is also seen in increased load and generation enquires seen by Transpower (Grid Owner).

Figure 33: Comparison of margins with the 2021 SOSA – Tiwai Remains sensitivity used for 2021

Figure 34: NZ winter energy margin reference case comparison 2021 and 2022

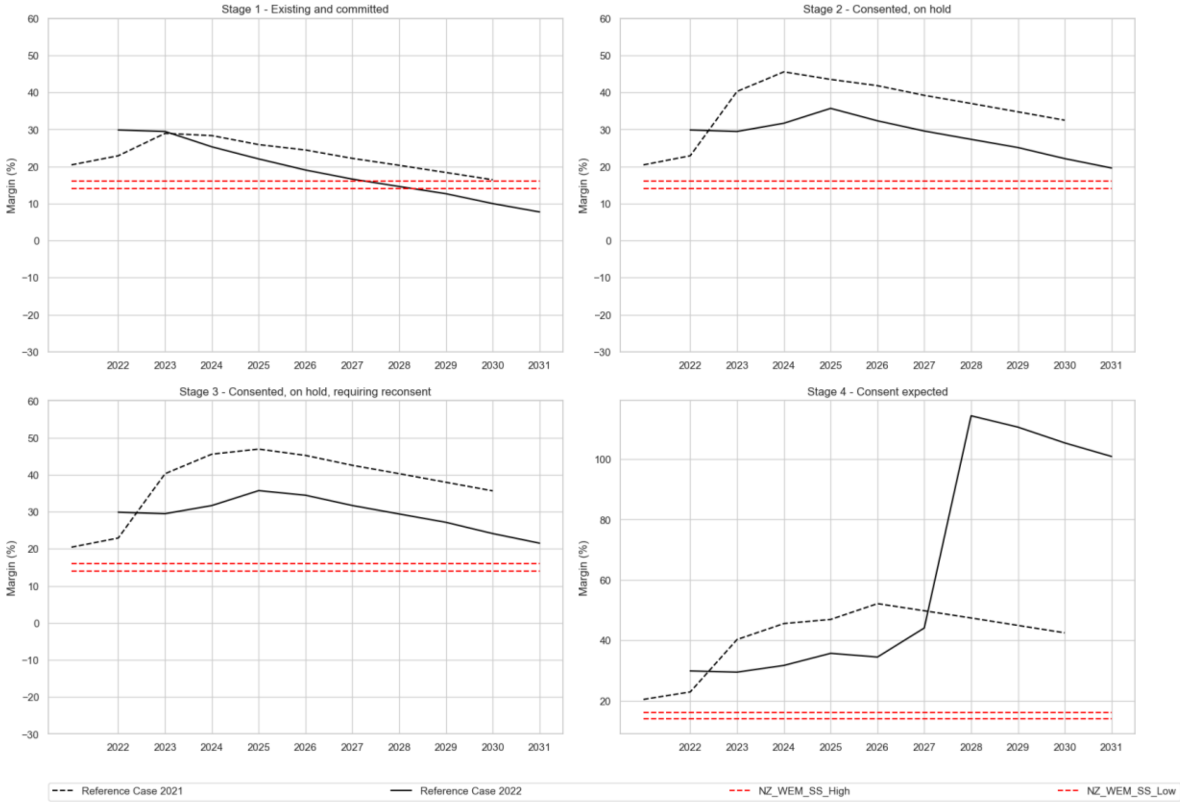
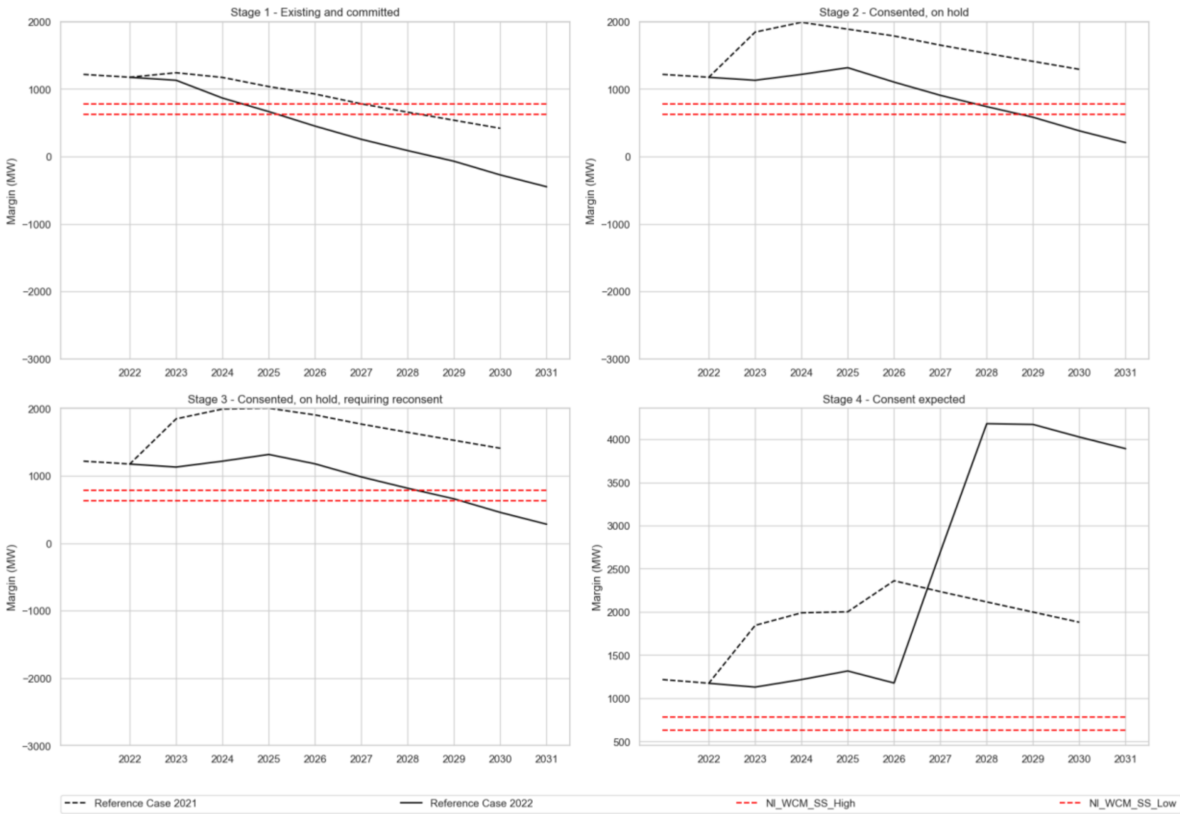


Figure 35: NI winter capacity margin reference case comparison 2021 and 2022



6.0 Maintaining security margins with greater proportions of renewable generation

6.1 Overview and Summary

The government has an aspirational target of 100% renewable electricity by 2030. In this section we look at the impact of increasing the proportion of renewable generation in 2030 on the NZ-WEM and NI-WCM. Our approach is to investigate five thermal generation scenarios, which consider progressively smaller amounts of thermal generation and increasing proportion of renewables. For each of these scenarios we estimate the contribution from renewable generation and other technologies that would be required to maintain the NZ-WEM and NI-WCM above the security standards.

This analysis is exclusively focused on security of supply and we have not investigated economic or technical issues outside of this brief. Consistent with our margin forecasts presented in Section 5.0, we do not attempt to forecast or otherwise determine the likelihood of whether any of these scenarios could occur.

This assessment shows that significant new supply additions will be required to replace existing thermal generation and increase the proportion of renewable energy to 100%, satisfy the increased future demand and maintain efficient levels of supply reliability. From our market survey of participants there are indications that there could be sufficient potential generation projects that could meet this increased need however the majority of these are unconsented and therefore less certain than other projects which we gather information about.

For the purposes of this chapter thermal generation refers exclusively to generation that is fuelled by either diesel, natural gas or coal[41].

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[41] Out analysis does not explore future supply options that may utilise thermal generation technologies that are carbon zero in some form.

6.2 Thermal Generation Scenarios

We have developed five thermal generation scenarios, described in Table 6 below, that consider progressively less thermal generation than current levels. The relative contributions to winter energy and capacity margins for each thermal generation scenario are shown in Figure 36 below.

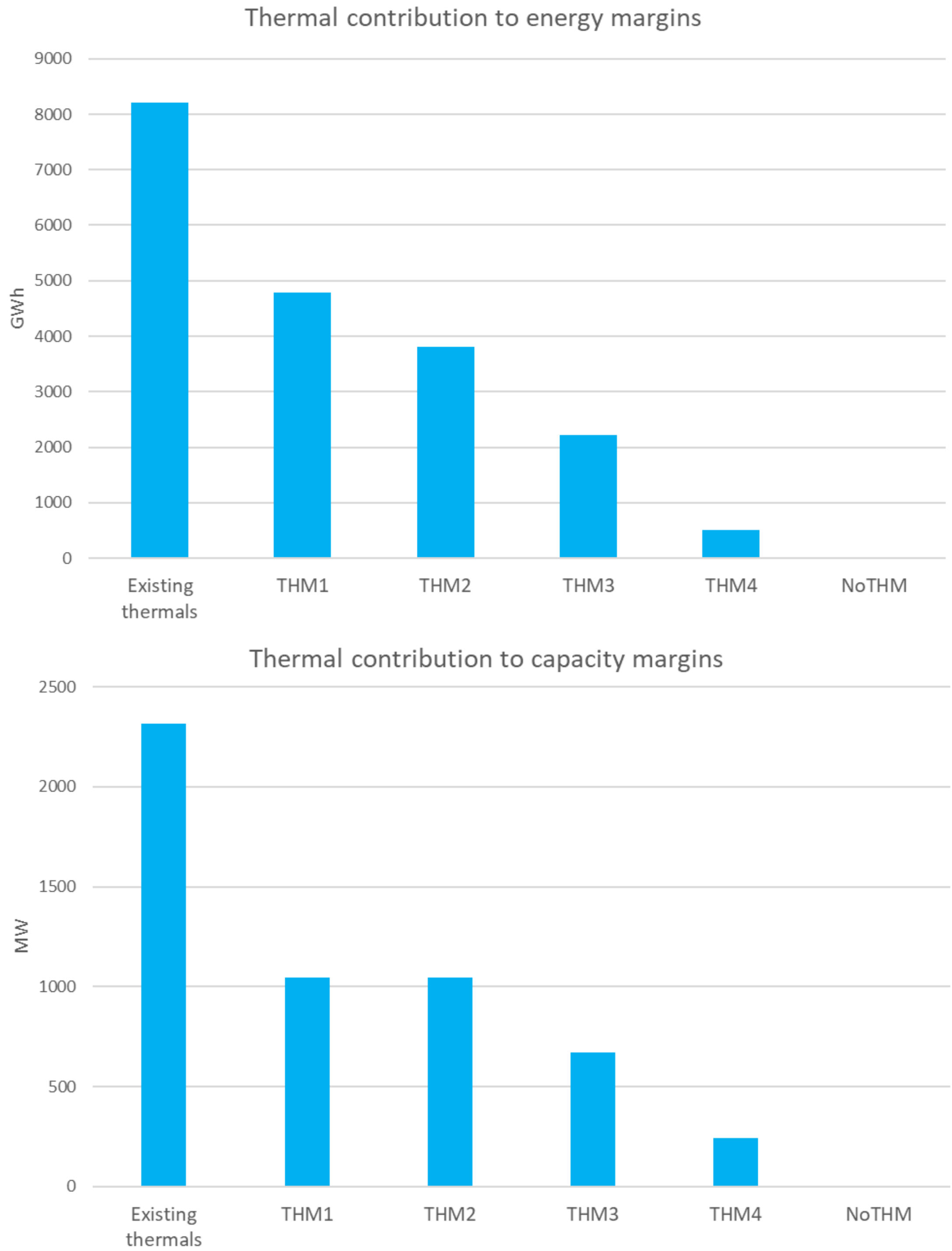
These thermal generation scenarios should not be interpreted as indicating a potential or likely pathway to higher proportions of renewable generation. It is possible that the pathway to higher proportions of renewable generation will involve step changes in thermal generation that vary from the thermal generation scenarios that this analysis considers.

Table 6 Thermal generation scenarios

Scenario	Description
THM1 One Rankine unit (dry year support only), one CCGT remains	One Huntly Rankine unit remains for dry year support, while two are decommissioned. We assume that this Rankine unit will not contribute to winter capacity margins. One Closed Cycle Gas Turbine generation unit (CCGT) remains at Huntly which contributes to both energy and capacity margins with the other CCGT at Stratford (TCC) is decommissioned. All other remaining thermal generation are available to contribute to winter energy and capacity security margins.
THM2 No Rankine units, one CCGT remains	All Huntly Rankine units have been decommissioned. Note this scenario has the same contribution to the NI-WCM as the THM1 scenario as shown in Figure 36. This is because even through THM1 has one Huntly Rankine unit in service, it does not contribute to the NI-WCM. The CCGT at Huntly continues to contribute to winter energy and capacity security margins. All other remaining thermal generation are available to contribute to winter energy and capacity security margins.
THM3 No Rankine or CCGT units	The CCGT and all Rankine units at Huntly have been decommissioned.

Scenario	Description
	All other remaining thermal generation are available to contribute to winter energy and capacity security margins.
THM4 Whirinaki and cogeneration	Only gas co-generators and the Whirinaki diesel generator remain. All other remaining thermal generation are available to contribute to winter energy and capacity security margins.
NoTHM No thermal incl. Whirinaki and cogeneration	There is no gas, coal or diesel thermal generation.

Figure 36: Thermal contribution to margins



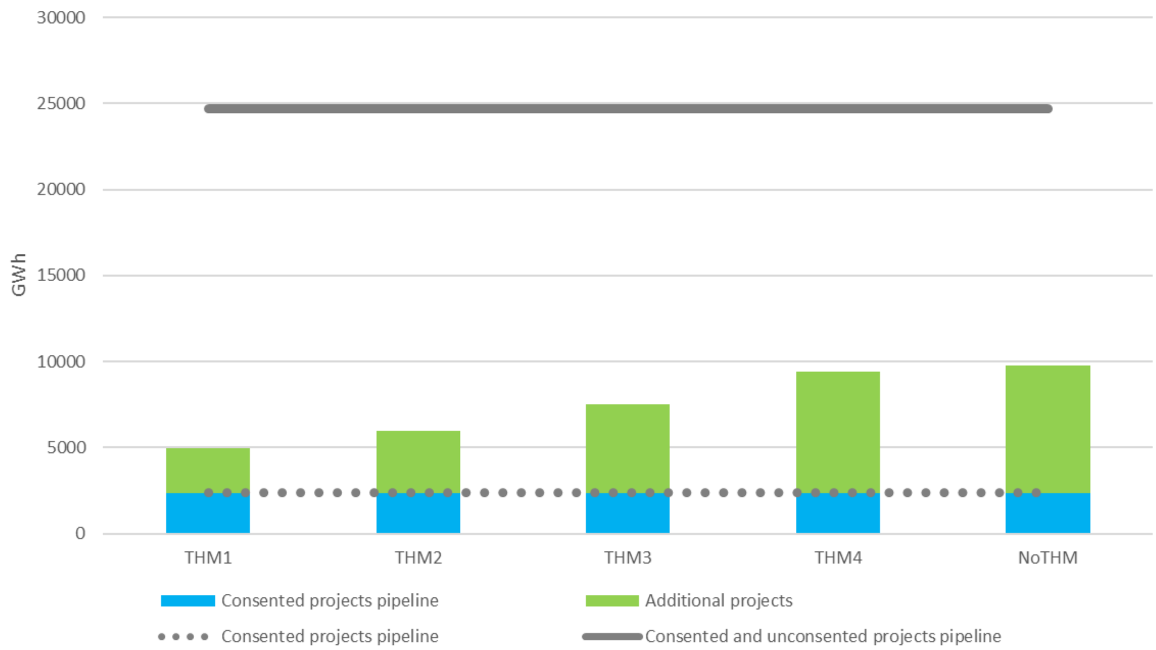
6.3 Security Margin Impacts

6.3.1 Winter Energy Margins

Figure 37 presents the additional contribution to NZ-WEM that would be required from new supply projects to maintain margins above the upper security standard in 2030. These contribution calculations use the reference case. The blue bars show potential contributions from known consented renewable projects in the supply pipeline (Stage 3 in Table 2: Potential supply pipeline). The green bars show the potential levels of contribution required from non-consented projects. The grey dashed line shows the consented projects pipeline and the grey solid line shows the consented and unconsented project pipeline.

The assessed thermal scenarios indicate that majority of the renewable contribution to displace the thermal generation in each of the scenarios, supply the increased demand and maintain the NZ-WEM above the security standards will be required from currently unconsented projects. This requirement increases as the amount of thermal generation on the system reduces. The unconsented pipeline has very large renewable generation potential which would contribute to the NZ-WEM. In this instance the unconsented pipeline is sufficient to supply the additional required energy to maintain the NZ-WEM at the upper security standard. As noted previously given these projects are currently unconsented, there is a higher level of uncertainty around if when these projects will be delivered.

Figure 37: Energy contribution required in 2030 to meet the NZ winter energy margins upper security margin of 16% under different thermal generation scenarios



6.3.2 Winter Capacity Margins

Figure 38 presents the additional contribution to the NI-WCM that would be required from new North Island projects to maintain winter capacity margins above the upper security standard in 2030[42]. We use the same format as above to designate contributions from known, consented and unconsented renewable and battery projects in the project pipeline.

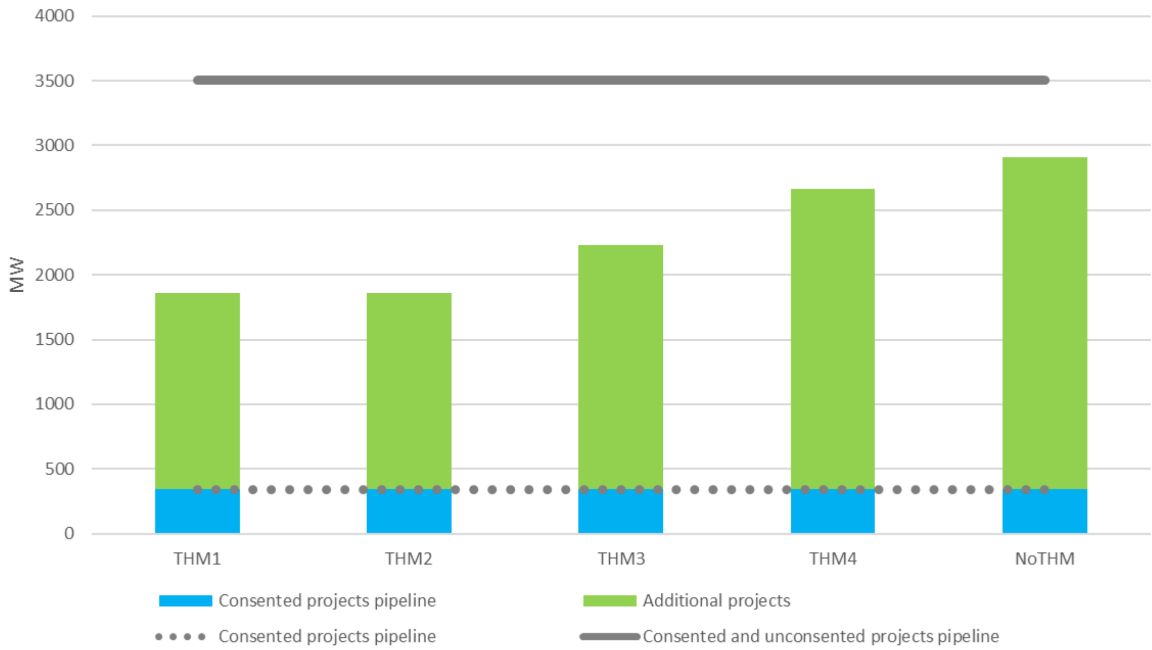
The extent to which South Island generation can contribute to NI-WCM is limited by the capacity of the HVDC. For our assessment of capacity margins, we assume that the current Northward capacity of the HVDC is constrained to ~950 MW[43].

Similar to the winter energy assessment, for the winter capacity assessment, majority of the renewable contribution to displace the thermal generation, supply the increased forecast peak demand and maintain the NI-WCM above the security standard will be required from currently unconsented projects. This requirement increases as the amount of thermal generation on the system reduces. The reliance on disclosed unconsented projects for the capacity margin is even greater than for the energy margin given majority of the disclosed projects that are still unconsented are wind and solar which have a lower contribution to winter peak demand compared to energy over the winter period.

There is currently a large amount of unconsented North Island projects in the pipeline which can potentially contribute ~3500 MW to the NI-WCM. This indicates sufficient potential capacity (including the unconsented projects) to supply the expanded requirements to maintain the margins. However as noted earlier there is a larger amount of uncertainty associated with unconsented projects.

[42] Note the THM1 scenario has the same contribution to the NI-WCM as the THM2 scenario. This is because even through THM1 has one Huntly Rankine unit in service (whereas the THM2 scenario has none), this unit does not contribute to the NI-WCM in the THM1 scenario.
[43] This is without the HVDC fourth cable.

Figure 38: Additional capacity contribution from North Island projects required in 2030 to meet the NI-WCM security standard



6.3.3 The New Zealand Battery Project

The government's New Zealand battery project investigates options to resolve New Zealand's 'dry year risk' problem in a highly renewable system. One of the options being considered is the Lake Onslow pumped hydro scheme. The Interim Climate Change Commission indicated that this scheme "would provide for a pumped hydro station of about 1,000 MW to be built and storage capacity of around 5,000 GWh". We have considered this configuration (1000MW, 5000GWh) for our assessment in this section.

The relative contribution that this project could make to our 'NoTHM' scenario is shown in Table 7. As can be seen, Lake Onslow could potentially make a substantial contribution to the NZ-WEM. We note that in the first ~2 years after commissioning, while its reservoir is being filled, the scheme could have limited ability to contribute to the NZ-WEM, as shown by the different scenarios of available storage at the start of winter in the initial years of operation.

Its contribution to NI-WCM could also be large but this is dependent on future northwards capacity of the HVDC and other surplus generation capacity in the South Island. Surplus South Island generation capacity could be due to additional investment in South Island generation (e.g. development of currently unconsented generation) and/or Tiwai exiting without being replaced with similar-sized loads in the South Island, thus resulting in surplus South Island generation capacity available for export to the North Island. Increasing HVDC north transfer capacity would enable greater contribution of Lake Onslow and other surplus South Island generation capacity to contribute to the NI-WCM[44].

Table 7: Potential Contribution from Lake Onslow to Security Margins – NoTHM scenario

Margin	Lake Onslow contribution	Lake Onslow contribution as % required to maintain upper security standard in NoTHM scenario
New Zealand winter energy	~5000 GWh (lake full at the end of summer)	~51%
	~2500 GWh (lake half full at the end of summer during initial fill)	~26%
	~1250 GWh (lake quarter full at the end of summer during initial fill)	~13%
North Island winter capacity - *With HVDC upgraded with a 4th cable and only consented generation developed*	~570 MW	~20%
North Island winter capacity - *With HVDC upgraded with a 4th cable, consented generation developed, and an additional 550MW SI net generation capacity*[45]	~20 MW	~1%

[44] We note that other HVDC long-list options are being considered by Transpower (Grid Owner) as part of the Net Zero Grid Pathways project. See pages 15 and 16 here:
[45] The additional net generation capacity in the South Island could represent development of unconsented South Island generation projects or exit of Tiwai without replacement loads.

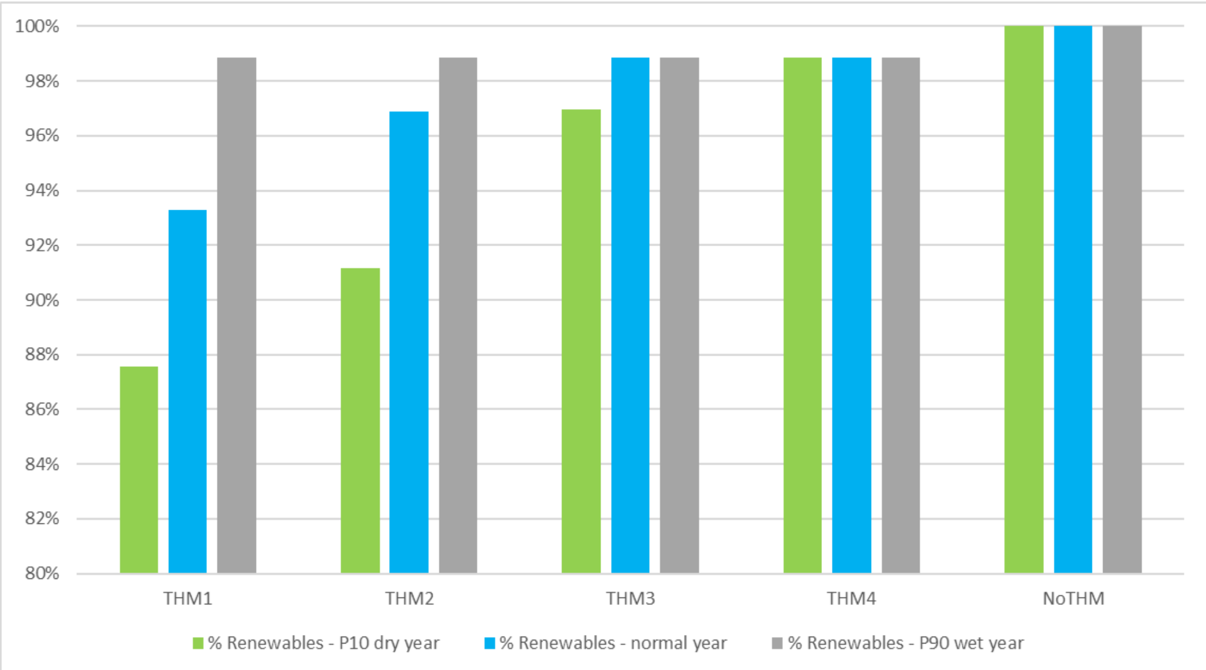
6.4 Renewable Generation Percentage Estimates

Figure 39 shows indicative estimated renewable generation as a percentage of forecast annual demand for each thermal generation scenario for the reference case. Renewable generation percentages are shown for a normal hydrological year (blue bar), as well as dry (P10, green bar) and wet (P90, grey bar) hydrological years. P10 and P90 refer to the lower and upper percentile range of historical inflows respectively. The amount of renewable generation assumed for each scenario is equal to that required to maintain NZ-WEM at the upper security standard.

If only renewable generation is used to maintain the NZ-WEM security standards this implies a level of renewable generation 'over build' for the 'THM2' scenario and other scenarios with less thermal generation. This means for wet years the amount of renewable generation capacity will be greater than required to meet demand resulting spilling of renewable resources when there is insufficient storage capability.

Except for the 'NoTHM' generation scenario we assume the maximum amount of renewable generation (produced in a given year) is constrained by gas cogeneration. This type of generation is likely to operate on a 'must run' basis given that it is likely to also generate process heat for its host industrial facility.

Figure 39: Indicative, estimated renewables percentages: Medium Demand scenario and as required to maintain a 16% security standard



The use of alternative technologies, such as pumped storage or large industrial demand response, have not been considered in our analysis and these would alter our P10 and P90 estimates. These alternative technologies may also help to reduce the quantity of excess generation developed (and excess energy generated).

The amount of new renewable generation that this analysis assumes in order to meet energy margin security standards would not be sufficient to maintain the NI-WCM above the upper security standard. It is uncertain as to exactly how the NI-WCM would be maintained for each thermal generation scenario however it is likely that a mix of complementary technologies could be used. Intermittent generators like wind and solar generation have a lower contribution to the capacity margin than the energy margin[46]. If some renewable generation over build was found to be an economic option to help contribute to the NI-WCM, then this would increase the renewable generation percentages that we show in Figure 39. Other options with higher contribution to peak load periods could also complement the intermittent generation. These would be large scale demand response, storage, or renewable thermal fuels such as hydrogen or biomass.

[46] This is because intermittent generation output over a period of time (such as during the winter months for the winter energy margin) is relatively more certain than its output during individual half-hours in winter when the load is peaking (as required for the capacity margin).

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Appendices for Security of Supply Assessment 2022

System Operator

Version: 2.0

Date: 30 June 2022

Contents

Appendix 1: Margin Assessment Methodology

1.1 Margin Assessment Methodology

1.2 Winter Energy Margins Assessment

There are two winter energy margins. The New Zealand 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:

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

For the purposes of calculating winter energy demand and winter energy supply winter is defined as the period from 1 April through to 30 September.

The components in the above formulas are defined in Table 1and Table 2.

Table 1: Summarising the New Zealand winter energy margin components

Component	Comprises of	Description
New Zealand expected energy supply (GWh)	Thermal Generation GWh	Maximum expected thermal generation available to meet winter energy demand allowing for forced and scheduled outages, fuel supply availability and operational constraints
	Thermal Generation Forced and Scheduled Outages	5.4% for combined cycle gas turbines and 6.7% for coal-fired Huntly units
	Thermal Generation Fuel Supply Availability Deratings	Thermal deratings due to fuel availability are provided in main report, Section 4
	Thermal Generation Operational Constraint Deratings	Thermal generation has been reduced by 92 GWh in the North Island to reflect spinning reserve and frequency keeping requirements1

[1] This is different than that suggested in the Electricity Authority's Security Standards Assumption Document. 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.

Component	Comprises of	Description
	Mean Hydro generation GWh	Expected winter hydro generation based on mean hydro inflows over the historic record
	Hydro storage at 1 April	Hydro storage at the start of winter is 2,750 GWh
	Other Generation GWh	Expected winter energy available from cogeneration2, geothermal generation, wind generation, solar generation, embedded generation and batteries based on information from generation companies and supplemented by market information. Domestic solar generation and domestic battery generation is as derived for the winter energy demand forecast.
New Zealand expected energy demand (GWh)	NZ Energy Demand GWh	Expected winter energy demand on a gross basis, inclusive of transmission losses and adjusted for demand response. Where gross demand includes embedded generation.
	Transmission Losses	Transmission losses are calculated by calculating GXP offtake quantities and applying a static loss factor of 3.5 % for New Zealand
	Demand Response	Winter energy demand has been reduced by 2 per cent to allow for voluntary demand response. 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.

[2] 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.

Table 2: Summarising the South Island winter energy margin components (where different to above)

Component	Comprises of	Description
Expected HVDC transfers south (GWh)	HVDC GWh	Expected winter HVDC transfers received in the South Island. It is assumed that the North Island will be able to supply the South Island with 2,101 GWh (480 MW average transfer) 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 is used.
	Hydro storage at 1 April	Hydro storage at the start of winter is 2,400 GWh
	Transmission Losses	A static loss factor of 4.5 % is used for South Island

1.3 North Island Winter Capacity Margin Assessment

The North Island Winter Capacity Margin is calculated as:

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

For the purposes of calculating winter energy demand and winter energy supply winter is defined as the period from 1 April to 31 October.

The components in the above formula are defined in Table 3.

Table 3: Summarising North Island winter capacity margin components

Component	Comprises of	Description
North Island expected capacity (MW)	Thermal Generation MW	Installed capacity of thermal generation allowing for forced and scheduled outages, fuel supply availability and operational constraints
	Thermal Generation Forced and Scheduled Outages	3% for all thermal generation

Component	Comprises of	Description
	Thermal Generation Fuel Supply Availability Deratings	No thermal deratings due to fuel availability are applied except for low gas supply sensitivity, as discussed in Section 4 of the report.
	Thermal Generation Operational Constraint Deratings	No thermal deratings due to operational constraints are applied
	Hydro Generation MW	Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and de-rated to account for operational constraints
	Hydro Generation Forced and Scheduled Outages	2% for all controllable hydro generation
	Operational Hydro Generation Deratings	Matahina, Patea and Tokaanu are derated by 13 MW, 5 MW and 20 MW respectively to account for their limited short-term storage. Waikato hydro scheme is derated by 60 MW to account for the impact of chronological flow constraints.
	Other Generation MW	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. Assumed contributions to winter peak demand, as a percentage of capacity are: • Flexible run-of-river hydro: 81.2% • Inflexible run-of-river hydro: 72.0% • Geothermal: 91.7% • Cogeneration: 61.0%

Component	Comprises of	Description
		For wind generation, this assessment assumes a wind capacity contribution of 25 per cent as defined in the SSAD. For large scale solar generation and batteries, this assessment assumes a capacity contribution of 5% and 97% respectively. This will be further refined as actual operational data is obtained.
North Island and South Island expected demand (MW)	NI and SI peak demand MW	Expected average of the highest 100 hours of demand in winter inclusive of losses, by Island. This is referred to as H100 NI demand. Demand is gross, inclusive of transmission losses and adjusted for demand response.
	Transmission Losses	Transmission losses are calculated by calculating GXP offtake quantities and applying a static loss factor of 2.88% within the North Island, and 4.88% within the South Island
	Demand Response	An allowance of 176 MW is made for demand response and interruptible load in the North Island at peak times. No allowance is made for South Island peak-time demand response or interruptible load.
Expected HVDC transfer north	South Island MW	The net amount of MW the South Island can supply to the North Island during peak periods. Surplus supply (SI supply capacity minus SI peak demand) is constrained by the capability of the HVDC as defined in Electricity Authority's Security Standards Assumption Document.

Appendix 2: Demand Forecasting Modelling

2 Demand Forecasting Modelling

2.1.1 Purpose

This appendix describes the demand forecasting modelling suite (‘the modelling suite’) used by Transpower’s Grid Investment and Modelling team to forecast winter energy and peak demand.

2.1.2 Introduction

The modelling suite can forecast average demand, in MW, at each Grid Exit Point (GXP) and each half hour trading period. Having a modelling suite that produces this level of detail provides a mechanism for modelling the effect of solar Photo Voltaic (PV), batteries and ‘smart’ charging of electric vehicles at a daily profile level. The full set of profiles also assists in producing a wide variety of outputs for different purposes such as a forecast of winter peak demand. While the security margin assessment doesn’t require GXP or regional level detail, we use the full capabilities of the modelling suite to produce the forecast.

The modelling suite can produce different scenarios with different assumptions for base energy growth, base peak growth or different uptakes of new technologies.

2.1.3 Two stage approach

To account for future levels of demand growth to be different to historic levels and to be able to satisfy all the requirements of the modelling suite we have developed a two-stage forecasting method illustrated in Figure 1. The two-stage approach provides a convenient ‘break’ in the modelling suite for a variety of reasons, for example the outputs of the first stage can provide a measure of base growth for energy and peak demand.

The outputs of stage one does not contain any half-hourly profile data. The peak is separated by season and year, and by nation, island and region. The energy outputs are by year, and nation and island. A simple flow chart for this process in shown in Figure 1. The customer (e.g. electricity distributor’s) forecasts at the GXP level are an important part of this process.

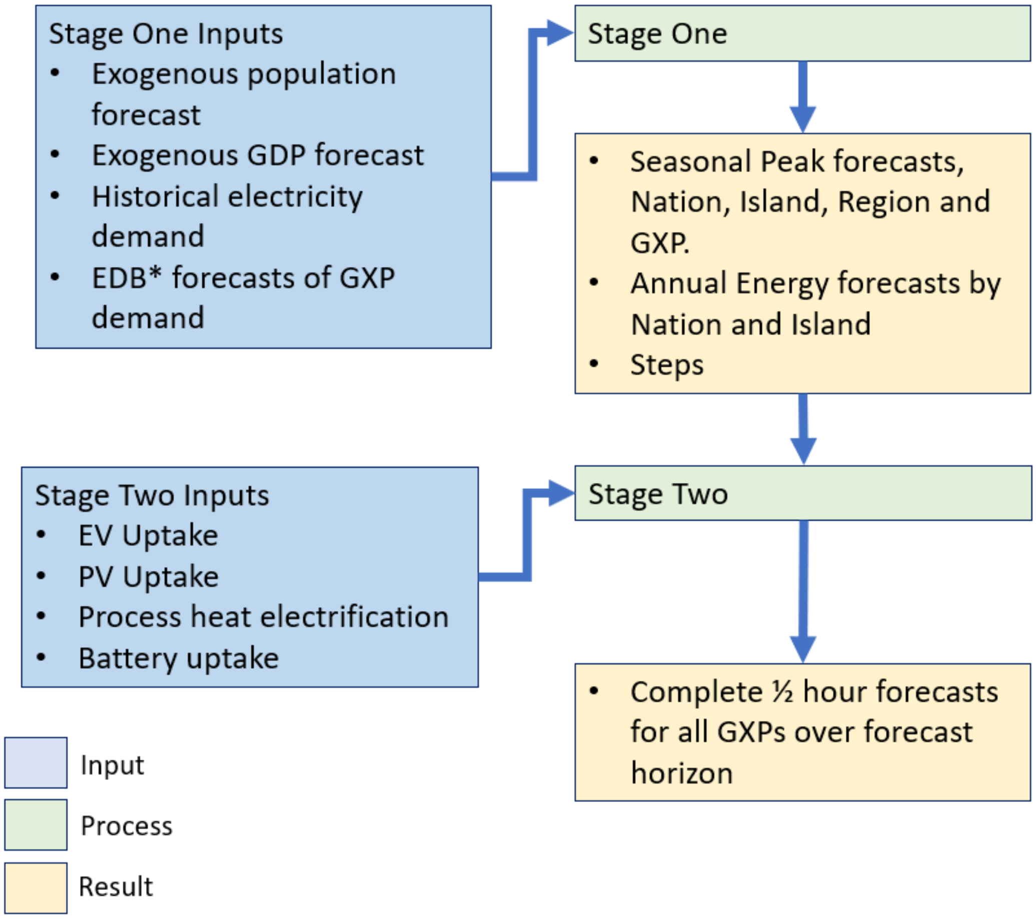
2.1.4 Generating base profiles

Base profiles are initially generated from historical data and scaled to match the stage one peak and energy growth. A reconciliation process is used, at the trading period level, to best preserve the hierarchy of the stage one forecasts.

2.1.5 Adding in new technologies

The new technologies added in stage two; electric vehicle charging, domestic solar PV, domestic batteries and electrification of process heat will all have an associated daily profile. These profiles, which can be regional, seasonal and specific to new industries say, are added on to the base profile. Some new technologies, such as batteries and smart electric vehicle charging can respond to the existing profile and adapt their profiles to ‘fill-in’ any troughs. Further details of the profiles associated with the new technologies, and demand forecasting in general can be found in the report and appendices of Whakamana i Te Mauri Hiko[2].

*Figure 1: A high level diagram of the two-stage process, the first stage produces a hierarchy of seasonal peak and annual energy values of the forecast horizon, stage two creates complete half hourly profiles at every GXP over the forecast horizon. *EDB is an Electricity Distribution Business.*



2.1.6 Embedded generation

Other than domestic solar PV and domestic batteries, there is no forecast growth of embedded generation in our suite. Historical embedded generation profiles are used to model the effect on the forecast profiles at the GXP level.

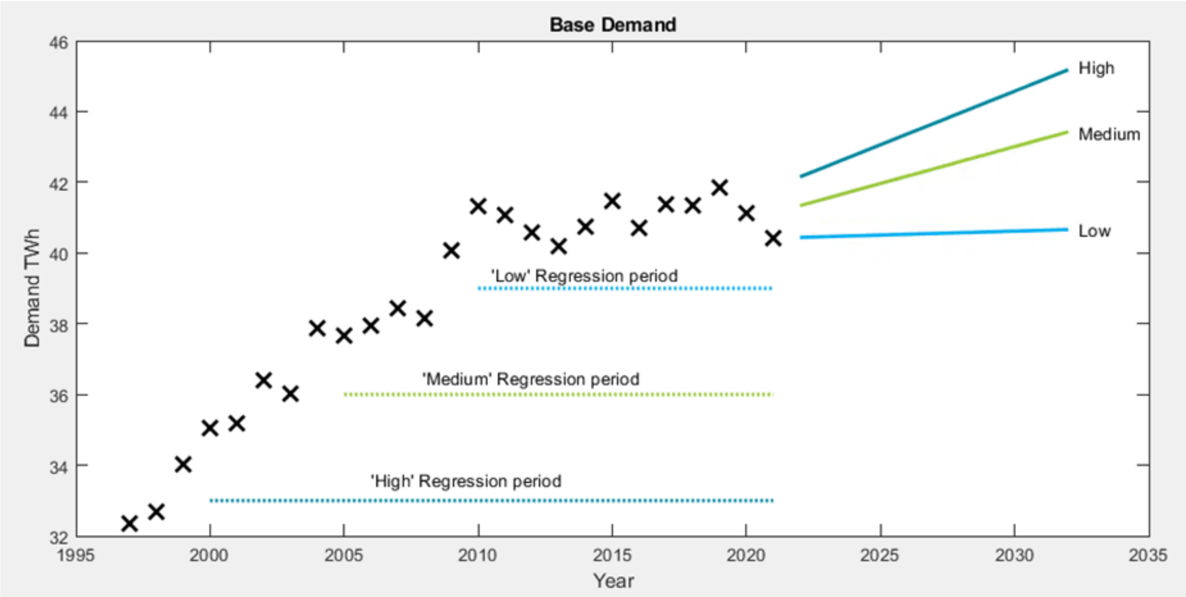
2.1.7 Reference scenario (case) and demand sensitivities

The modelling suite can be run to generate forecasts covering a range of different scenarios. The scenarios can include different base growth of peak and energy (stage 1) and different uptakes of new technologies (stage 2). This year's annual security of supply assessment includes a 'Medium Demand' scenario which is being utilised for the reference case as well as 'Low Demand' and 'High Demand' scenarios which will be applied as sensitivities to the reference case. The Medium Demand scenario is modelled on the Whakamana i Te Mauri Hiko's 'Accelerated Electrification' scenario.

The base peak growth is not varied within the scenarios, the final peak will grow by virtue of the growth of new technologies across the different scenarios. New technology uptake rates for each demand scenario, including domestic solar PV and batteries, are based on different Whakamana i Te Mauri Hiko scenarios (see below).

The base energy growth rate for each scenario is achieved through an expected forecast based on different regression windows. A shorter regression window follows the recent trend of small growth while a longer regression window captures the larger historical growth. Such an approach is not perfectly robust but serves the purpose well here. The base demand and the regression periods are shown in Figure 2.

Figure 2: The base energy demand for the reference case and demand growth sensitivities derived from different regression periods.



2.1.8 Input assumptions

The uptakes of the new technologies are largely based on Transpower's Whakamana I Te Mauri Hiko. One notable adjustment is that the expected demand increase due to electric vehicles has been brought forward. This is to reflect the increase expected heavy vehicle electrification due to a government pledge to decarbonise public transport bus fleet bus 2035[3]. The Low process heat assumption has also been adjusted down to align with the Business as Usual scenario. A summary of the scenario assumptions relating to Whakamana i Te Mauri Hiko is shown below. Battery uptake and the effect on demand and peak is small in the forecast horizon. Battery uptake for the reference case and demand growth sensitivities are most similar to the Whakamana I Te Mauri Hiko mobilise to decarbonise scenario.

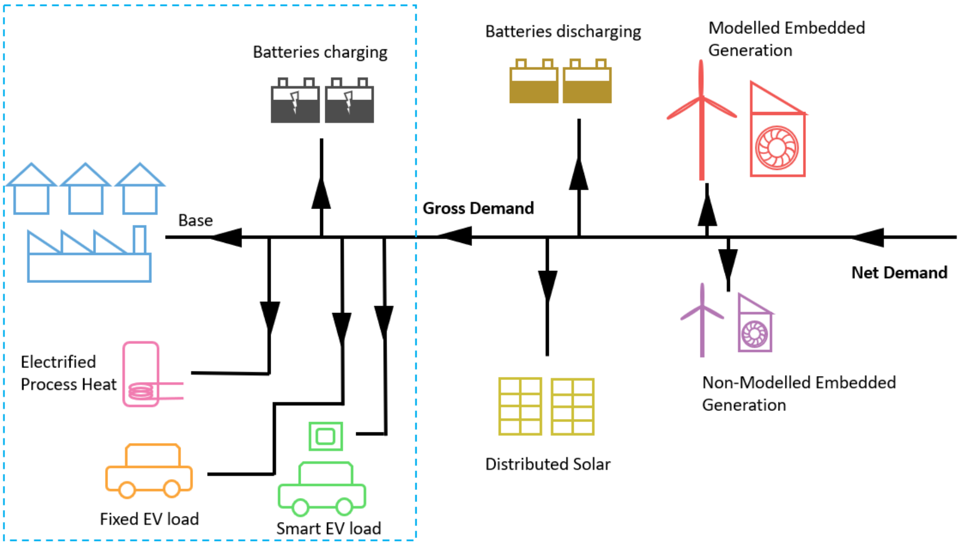
Table 4: Technology uptake assumption in relation to Transpower's Whakamana i Te Mauri Hiko scenarios

	Low	Medium	High
Process Heat	Business As Usual	Accelerated Electrification	Mobilise to Decarbonise
Total EV Load	Approximately 10% higher than Accelerated Electrification	Approximately 25% higher than Accelerated Electrification	Mobilise to Decarbonise at 2033, with slightly faster growth
Solar	Business as Usual	Accelerated Electrification	Mobilise to Decarbonise

2.1.9 Forecast

The modelling suite is required to separate out the gross and the net demand, i.e. batteries are treated separately depending on whether they are charging or discharging. Furthermore, embedded generation is categorised as 'modelled', or 'non-modelled'. In almost all cases modelled embedded generation is larger generation offered into the wholesale market. Winter supply contributions for modelled embedded generation are based on confidential information provided by generation companies and supplemented by historic market information. Winter supply contributions for non-modelled generation are as derived by the demand forecast process. A graphic of different types of supply and demand is shown in Figure 3. We have used the convention that all power is pointing towards the load or generator, thus giving any generation as a negative load.

Figure 3: The component of stage two and the different components of embedded generation. In this diagram generation is treated as a negative load.

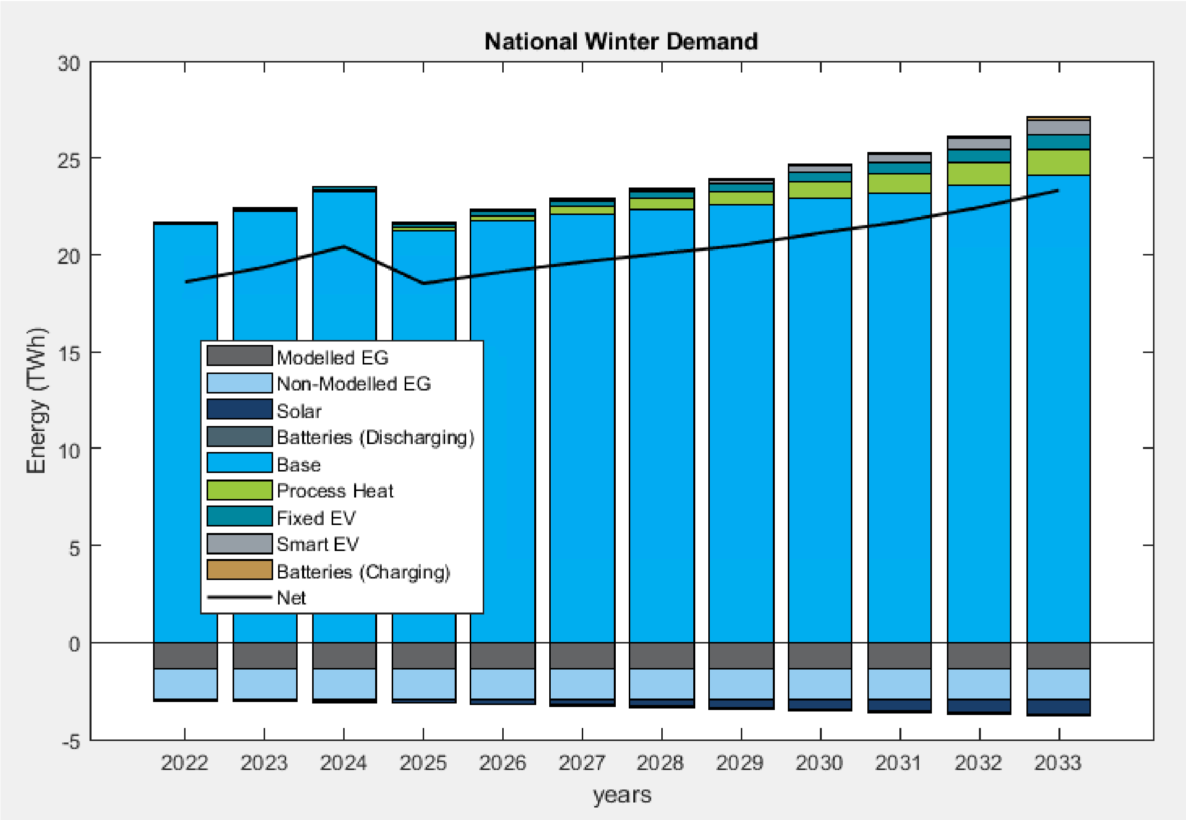


2.1.10 Winter Energy Demand

Forecast energy demand is reported for each island and the nation for every month. Energy demand can then be separated out into 'winter', which in this case is from 1 April to 30 September. The growth of New Zealand winter energy demand is shown in Figure 4[3]. The individual components that make up the gross demand, fixed and smart electric vehicle charging, electrification of process heat and batteries charging, are also shown. Winter energy demand as used in the assessment included transmission losses and demand response. These are added in as a post processing step by the System Operator's market and business team.

[3] This energy forecast includes Tiwai exit.

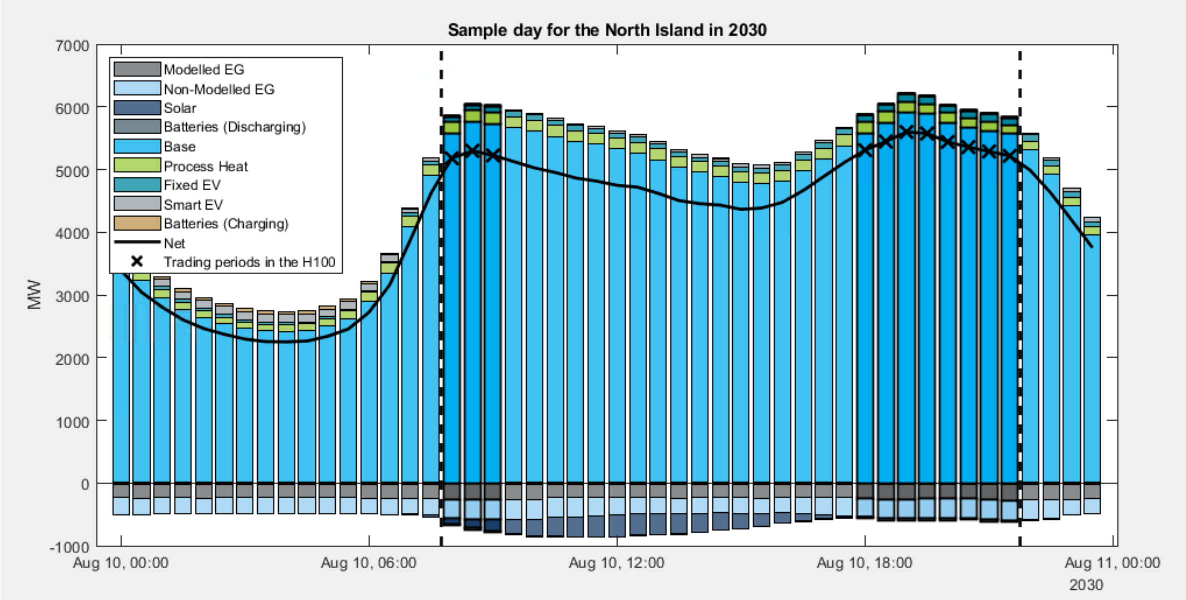
Figure 4: New Zealand winter energy demand including Tiwai exit. Tiwai was included in the reference case. The different types of embedded generation are shown.



2.1.11 Winter Peak Demand

Winter peak demand is reported as 'H100' demand, that is, the average of the highest 200 net demand trading periods during winter daytime. For this definition 'winter' is from 1st April to 31st October and daytime is from 7am to 10pm. A sample day for the North Island is shown in Figure 5, the trading periods from this day which are part of the H100 are highlighted. Winter peak demand as used in the assessment includes transmission losses and demand response. These are added in as a post processing step by the System Operator's market and business team.

Figure 5: A sample day for Medium Demand forecast showing which trading periods are used for the H100. The EG contributions during these periods are also reported. The net demand used for the H100 analysis is denoted by the marker 'x' and the trading periods have thicker borders.



The separate embedded generation components are reported. The components that make up the gross, i.e. base demand, electric vehicle charging, electrification of process heat and batteries charging, are also shown.

Winter peak demand for both Islands, showing the extent of the 'Low', 'Medium' and 'High' Demand scenarios is shown in Figure 6.

Figure 6: Winter peak demand over the 'Low', 'Medium' and 'High' Demand scenarios

Appendix 3: Gas Supply Availability

3 Gas Supply Availability: Reference Case

3.1 Introductions

Our reference case assumes that gas generators will have access to enough gas to contribute to security margins at their maximum available capacity, from 2022 until at least the end of the decade. This section outlines the basis for these assumptions.

This analysis has been undertaken given:

- Learnings from our 2021 assessment.
- Some our largest gas fields have an end of life within 10-15 years.
- Potential for reduced incentives for further investment in gas exploration and development. Reasons for this may include restrictions on oil and gas exploration and higher carbon prices.

3.2 Dry Year Gas Supply Margin

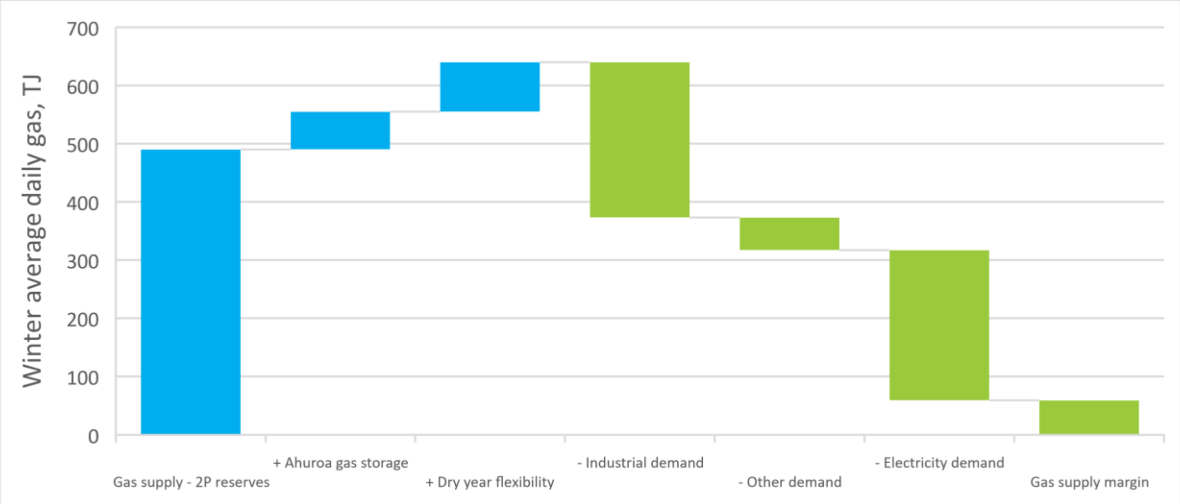
To evaluate gas supply adequacy, we estimate a dry year gas supply margin out for the next ten years. This margin is the estimated daily difference in gas supply and demand during a dry year emergency.

To estimate daily demand during a dry year emergency we assume:

- Huntly Rankine units are operating on coal;
- All gas generators operate at their maximum capacity, with an allowance for outages.
- There is material substitution of gas demand from major industrial gas users to gas generators during a dry year emergency. We have assumed that industrial gas users will reduce their demand, in aggregate, by 85 TJ /day.
- Gas demand for users other than gas generators is estimated using historical demand information, together with an allowance for future fuel substitution from gas to electricity.
- in general, Ahuroa Gas Storage facility has enough gas stored to operate at its maximum extraction rate throughout a dry year emergency.
- TCC is not decommissioned at the end of 2023.

An example dry year gas supply margin is shown below, where gas production is as estimated for 2023.

Figure 7: Example gas supply margin calculation: 2023 Business as usual



3.3 Dry Year Gas Supply Margin Scenarios

Dry year gas supply margins have been estimated for the following two scenarios[4]:

- **Existing gas generation**: Existing gas generation is available until at least the end of 2031. No new gas generation is commissioned.
- **New gas generation**: Additional 360 MW of gas generation is commissioned in 2024.

3.4 Dry Year Gas Supply Margin – Forecast 2P Reserves

We first estimate dry year gas supply margins with gas supply set equal to:

- Forecast production out to 2023, based on confidential information from gas producers.
- Thereafter forecast 2P reserves as published by the Ministry of Business Innovation and Employment (MBIE)[5].

Reserves are known gas resources that are anticipated to be technically and commercially recoverable[6]. The 2P designation means that there is a 50% probability that the reserves will be recovered.

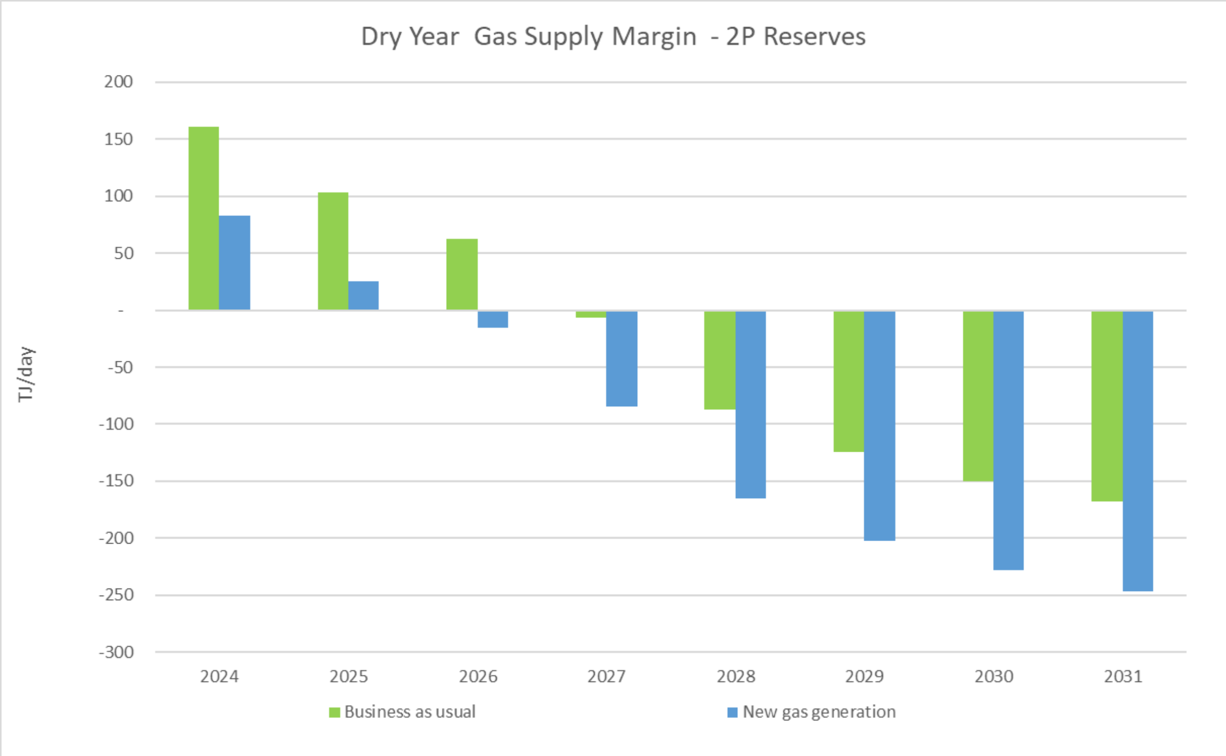
Based on our assessments, dry year gas margins are sufficient for 2022 and 2023. This is due to expected gas availability over the years and assumed reallocation of gas from gas users to electricity generation[7].

Dry year gas margins post 2023 are shown below. Positive margin below indicates sufficient gas availability from 2P reserves. For our reference case (with existing gas generation), margins are adequate from 2023 out to at least 2026, falling below zero in 2027. Considering additional gas

[4] Note we consider a low gas supply sensitivity separately as discussed in the next section.
[5] As of January 2021, published here.
[6] A more comprehensive definition is available here.
[7] This was observed in 2021. However, in the low gas supply sensitivity we reduce the extent to which gas users reduce usage during dry years for to enable increased gas for electricity generation.

generation, the margins fall below zero one year earlier (in 2026). For both these scenarios further gas reserves will need to be accessed from 2026 to maintain adequate dry year gas supply margins.

Figure 8: Dry Year Gas Supply Margins - 2P Reserves - From 2024



3.5 Contingent Gas Resources

Further investment in existing gas fields and facilities has the potential to unlock contingent gas resources and ensure ongoing gas supply security. Contingent gas resources are those which are potentially recoverable, but which are not currently considered to be commercially recoverable.

While it may be unlikely that all contingent resources will be able to be developed in the future, they arguably provide a yard stick of potential future gas supply. In their report for the Gas Industry Company, "Gas demand and supply projection – 2021 to 2035"[8], Concept Consulting considered that a range of 25% to 75% with a central estimate of 50% represented a plausible range for the conversion of contingent resources. In its subsequent 2022 report[9], Concept considered that 50% conversion of contingent reserves represented a conservative estimate[10].

We roughly estimate the approximate proportion of 2C contingent resources, as reported by MBIE, that would have to be developed in 2031 to ensure there is enough gas for gas generators during a dry year emergency. To do this we simple covert 2C contingent resources into an approximate daily supply quantity, by assuming that these resources would be recovered at a constant rate over a 15-year period.

We have received some feedback previously that the use of contingent resources in this manner may be overly optimistic. Following the same approach, we also use the difference between 3P and 2P reserves as a more conservative estimate of the possible future potential of existing gas fields. The 3P designation means that there is a 10% probability that the reserves will be recovered.

Table 5: Proportion 3P-2P and 2C gas resources that need to be converted into reserves to ensure adequate gas for electricity generation for existing and including potential new gas generation

Scenario	Proportion of 3P – 2P reserves that must be developed by 2031 to ensure gas security (rounded to nearest 5%)	Proportion of 2C reserves that must be developed by 2031 to ensure gas security (rounded to nearest 5%)
Existing gas generation	~85%	~30%
New gas generation	~125%	~45%

[8] See https://www.gasindustry.co.nz/assets/WorkProgrammeDocuments/Concept-supply-and-demand-study.pdf

[9] See https://www.gasindustry.co.nz/assets/CoverDocument/Gas-supply-and-demand-projections-2022.pdf

[10] In its 2022 report, Concept further noted that if using historical changes in reported 2P and 2C resources in New Zealand as a guide, it is likely that a quantity of gas equivalent to the majority of gas currently classed as contingent resources could be developed if demand was willing to pay gas prices seen historically (approximately $6/GJ). This conversion would significantly extend the time production could continue at levels projected for 2023 and 2024.

This analysis suggests that 3P-2P gas resources could potentially provide enough gas for dry year operation under the reference case assumptions for existing gas generation. Contingent gas resources (developed before 2031) could potentially provide enough gas for dry year operation under the reference case assumptions for existing and potential additional gas generation.

3.6 Conclusions

Our assessment suggests that there are enough gas reserves and contingent resources from existing gas fields to ensure on-going gas supply security for the 10-year assessment horizon. Development of these gas resources is reliant on continuing investment, and a market environment that is favourable for such investment, in upstream gas supply fields and associated infrastructure. Given that there are concerns as to level of investment in the gas sector in coming years, despite recent activity, we have included a Low Supply Sensitivity, which is discussed below.

Our assessment of gas supply security for our scenarios for this decade:

- Relies on publicly available information from MBIE.
- Assumes contingent gas reserves are a reasonable yardstick of the future potential of existing gas reserves. A more conservative approach, using the difference between 3P reserves and 2P reserves, indicates that gas supplies could tighten in the next half of the assessment horizon.
- Shows that with potential new gas generation, known contingent reserves are required.
- Assumes a level of gas reallocation from major industrial gas users for increased electricity generation during a dry year emergency, similar to that observed in 2021. We consider a lower quantity of such gas reallocation in the low gas supply sensitivity.
- Implicitly assume that there will continue to be investment in upstream gas supply fields and associated infrastructure.

4 Gas Supply Availability: Low Gas Supply Sensitivity

4.1 Introduction

Our Low Gas Supply sensitivity looks at a future where domestic gas production begins to decline substantially from 2026, consistent with a future where there is minimal investment in existing or new gas fields. In this sensitivity we also assume less gas is available for reallocation from industrial gas users for increased electricity generation during a dry year[11].

This sensitivity is intended to show the worst case for domestic gas production over the coming decade. It reflects concerns that future capital investment in the upstream gas industry may be at risk, given anticipated changes in gas demand and perceived uncertainties as to the transition away from carbon intensive fossil fuels. Further information can be found in the Gas Industry Company's 'Gas Market Settings Investigation' final report[12].

4.2 Dry Year Gas Supply Margin – Assumptions

To estimate dry year gas supply margins for the Low Gas Supply sensitivity we assume:

- The same set of baseline gas demand assumptions as for our reference case, except for gas reallocation.
- Assume less gas is available for reallocation from industrial gas users for increased electricity generation during a dry year. We consider this to be gas that could be reallocated for shorter-term market response. For this sensitivity we've estimated this to be 15TJ/day.
- Future gas supply is based on confidential information from gas producers out to 2023, information consistent with MBIE's forecast 2P reserves until 2025. From 2026 we adjust forecast 2P reserves by the ratio of total 1P reserves to total 2P reserves. Where total reserves are as published by MBIE13.
- Gas supplies are not supplemented by contingent gas resources from existing fields, new gas discoveries or LNG imports. This is consistent with the underlying assumption for this sensitivity that there will be minimal on-going investment in the upstream gas sector.

4.3 Forecast Dry Year Gas Supply Margin

Figure 9 shows forecast dry year supply margins for the Low Gas Supply sensitivity. Dry year gas margins are estimated to be insufficient from 2026. For these years, we will de-rate the installed capacity of gas generators. In 2029 there is insufficient gas available for peaking and baseload gas

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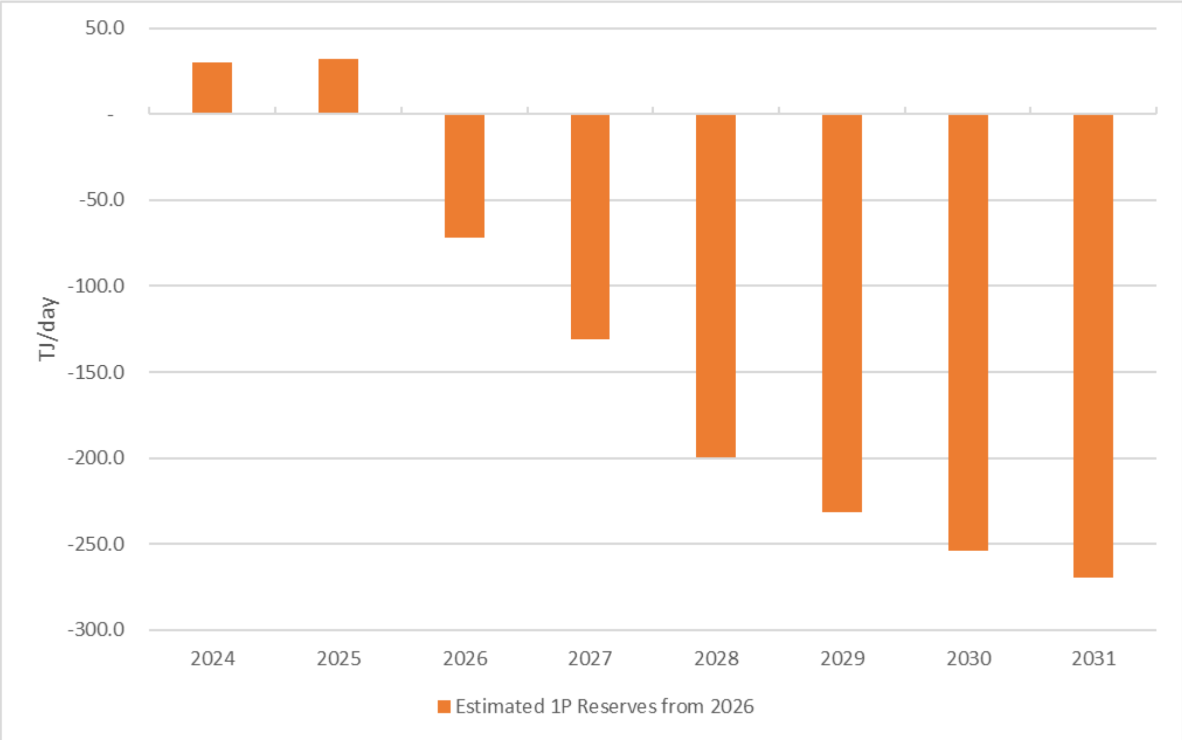
[11] This issue was also discussed in the system operator SOSFIP consultation in 2022.

[12] Gas Industry Company's 'Gas Market Settings Investigation' final report

[13] Specifically, we use MBIE's 'All fields' estimate, which is based on a probabilistic summation of all gas fields using a Monte Carlo simulation.

generators, which are estimated to require 228 TJ/day. In 2030 there is insufficient gas available for peaking, baseload and a substantial proportion of cogeneration gas generators. The availability of gas for cogeneration will largely depend on how a dwindling supply of gas is allocated to existing industrial gas users, which is beyond the scope of this assessment to consider. Therefore, we have applied no deratings to gas cogeneration plant.

Figure 9: Dry Year Gas Supply Margins - 1P Reserves From 2026



Appendix 4: Further Sensitivity Results

5 Chart Interpretation

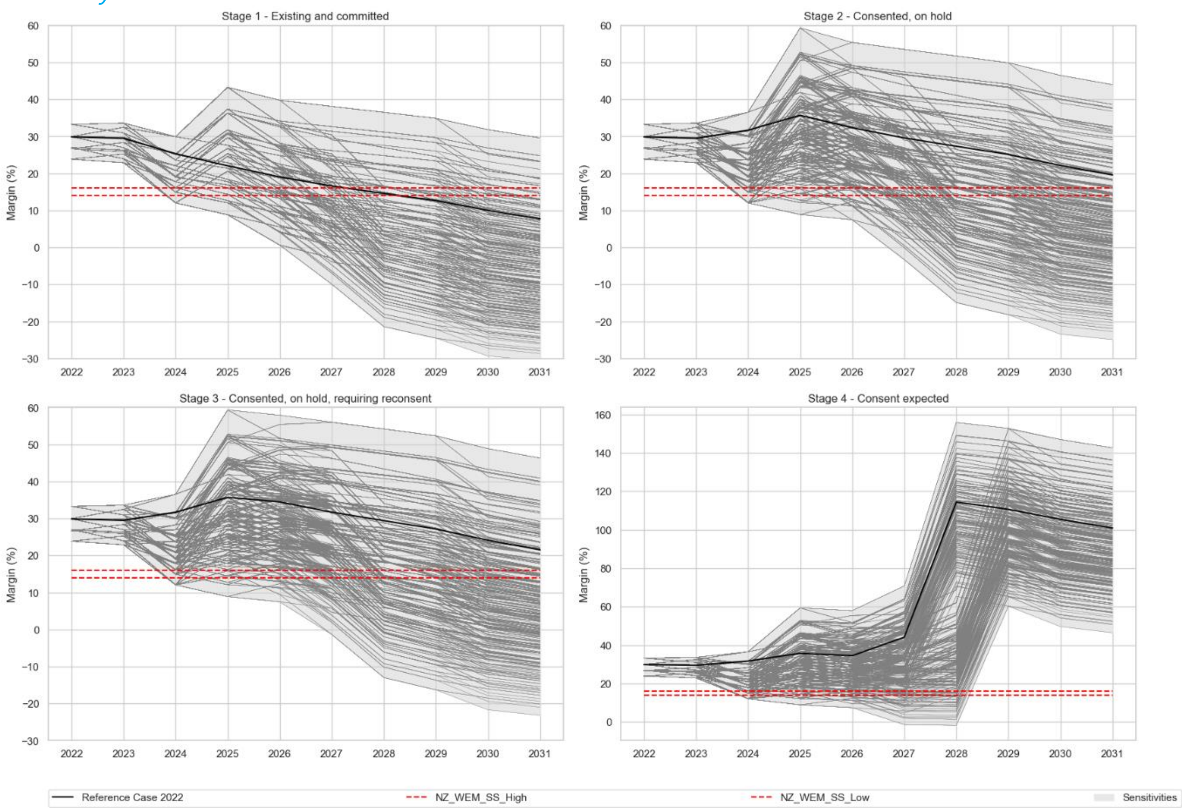
Historically, our assessment results have been shown using two types of charts, one to show margins for an individual scenario (low, medium, and high demand growth and gas constrained) and one to show the scenarios with a range of sensitivities (e.g., Tiwai remains, demand step changes). As our 2022 analysis is reflecting consultation feedback by transitioning to a single reference case with extensive sensitivity combinations, we have changed the method with which we present our findings.

5.1 Reference Case and all Sensitivity Combination Results

The reference case, the black line, was first shown against all possible combinations of sensitivities, the grey lines in Figure 10. This demonstrates the range of possibilities for the 10-year assessment horizon. Further to this, it provides a quantitative view of the distribution of the sensitivity combinations within the range.

The security standards are represented by the red dashed lines on this chart, which act as a reference to compare the capacity and energy margins against. The security standards are set by the Authority as upper and lower margins that represent an efficient level of reliability.

Figure 10 : Example chart, showing the NZ winter energy margin for the reference case and all sensitivity combinations



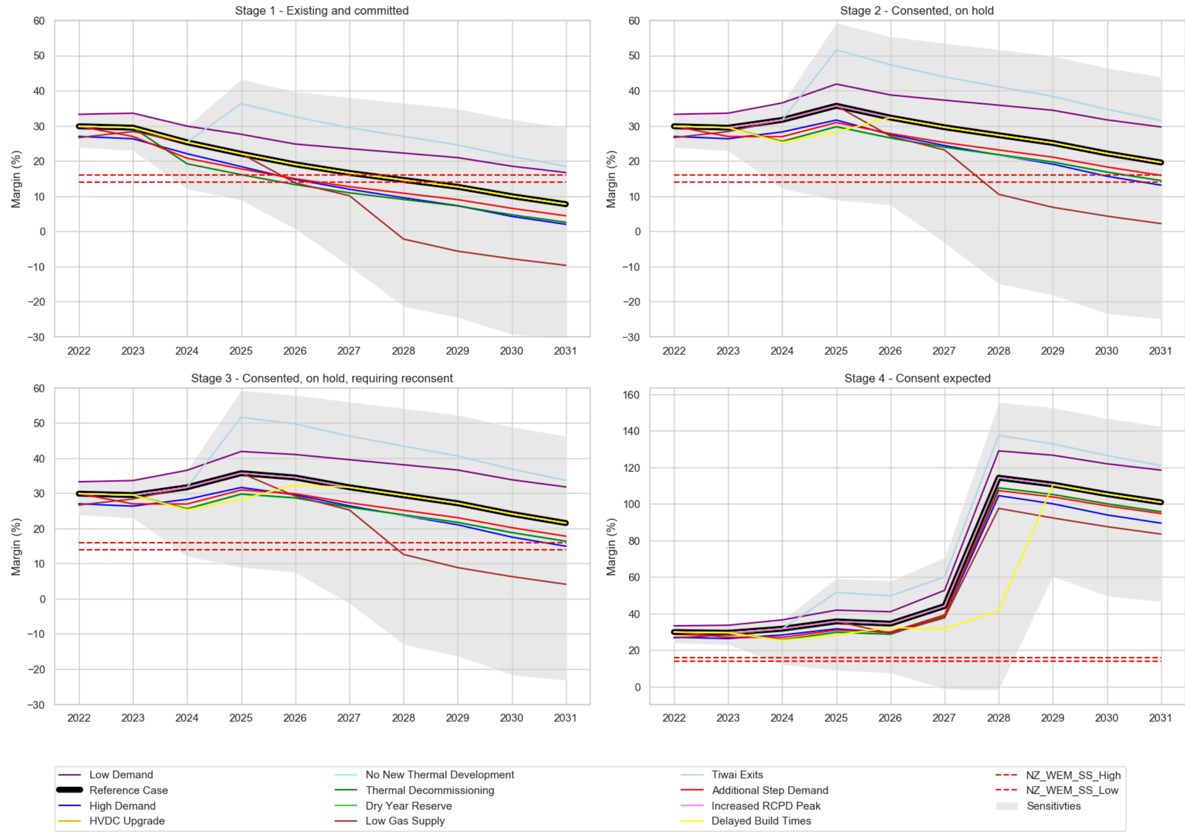
The capacity and energy margins are calculated with electricity supply from existing and committed generation (Stage 1), consented and on hold/awaiting market conditions to change (Stage 2), consented and on hold/awaiting market conditions to change – revision or reconsent required (Stage 3) and not consented, but likely sought within two years (Stage 4). As time passes, the demand grows, and the margin contributed by existing and committed generation decreases, excluding the influence of sensitivities.

We can draw conclusions from these charts by first looking at the proportion of margins with existing and committed generation which fall below the security standards. We then assess the adequacy of the pipeline of new supply projects to meet the security standards in the future. If there is a significant volume of new supply projects available that, when added to existing generation, results in a margin that exceeds the security standards, then it is likely the electricity system will be able to maintain the margin at or near the security standards.

5.2 Comparing the Reference Case with Individual Sensitivities

Sensitivities on the reference case are shown with plots in the format of Figure 11 for each stage of electricity supply (Stages 1-4). The reference case is plotted as the solid black line and the margins for each sensitivity are shown as well. Each sensitivity's margins are shown with all other sensitivities turned off and with medium demand growth, with the exception of the low and high demand growth sensitivities. The low and high demand growth sensitivities are the reference case with either the low or high demand forecast instead of the medium demand forecast. The grey shaded areas represent the range of all combinations of sensitivities possible for the available generation supply. The security standards are again represented by the dashed lines which act as a reference to compare the margins against. These figures isolate the effect of each sensitivity on the reference case from each other.

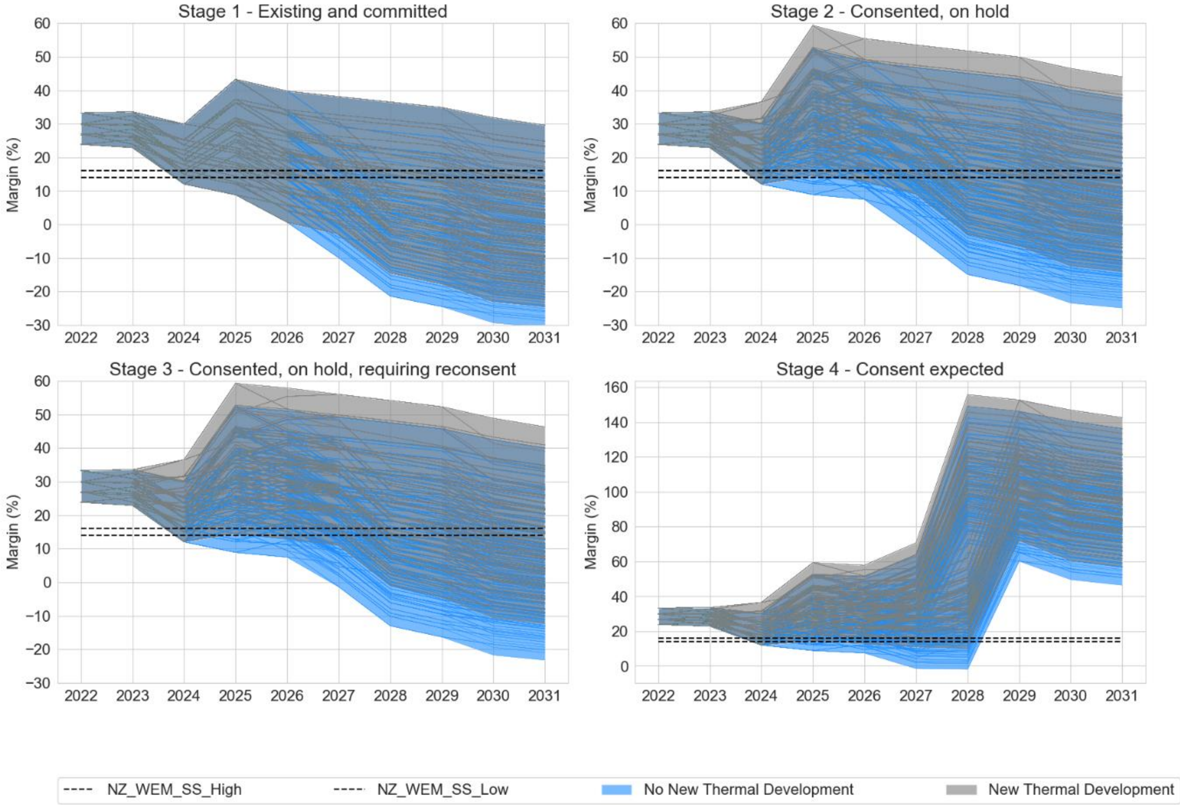
Figure 11 Example chart, showing NZ winter energy margins for the reference case and independent



5.3 Impact of a common sensitivity on sensitivity combinations

Figure 12 shows an example of analysing the effect of a particular sensitivity in more detail. In this example, we are focusing on the low gas supply sensitivity. The grey lines represent all possible combinations of all sensitivities with Thermal decommissioning set to false. The blue lines represent all possible combinations of all sensitivities with Thermal commissioning set to true. These plots again show the security standards as dashed lines. These plots demonstrate the impact of sensitivities interacting with each other. This highlights any significant changes to the margins caused by certain sensitivity combinations. Conversely, certain sensitivities may exaggerate the margins when not viewed in combination with other sensitives.

Figure 12 Example chart, showing the effect of one sensitivity on all sensitivity combinations



6 Further Sensitivity Results

6.1 New Zealand Winter Energy Margin Supply Sensitivities

Figure 13: New Zealand Winter Energy Margin Thermal Decommissioning Sensitivity

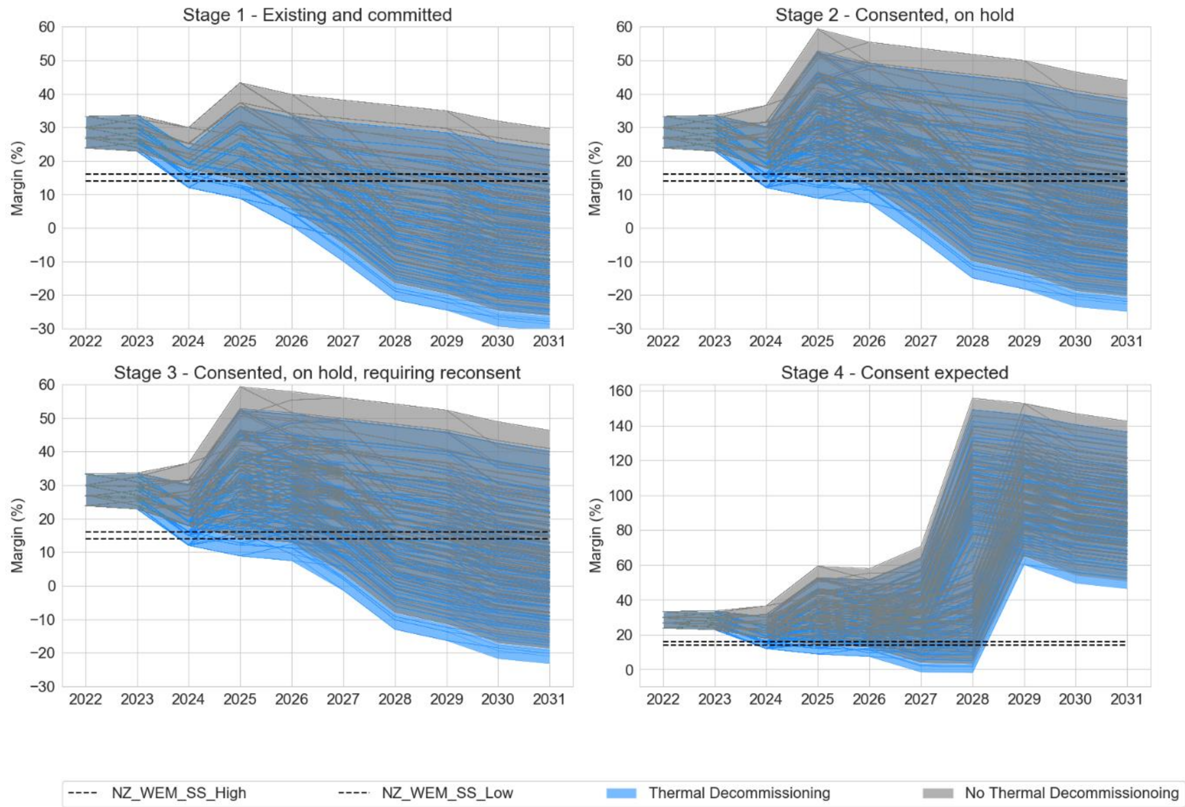


Figure 14: New Zealand Winter Energy Margin Dry Year Reserve Sensitivity

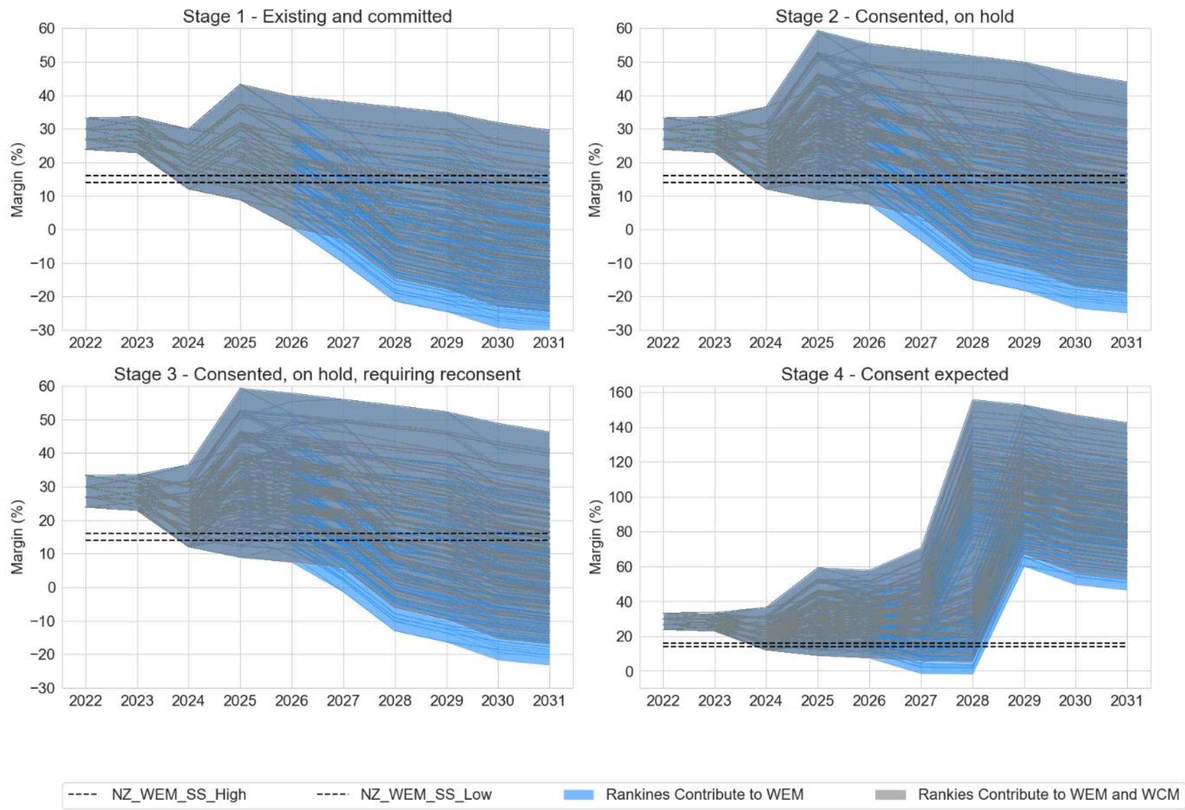


Figure 15: New Zealand Winter Energy Margin Low Gas Sensitivity

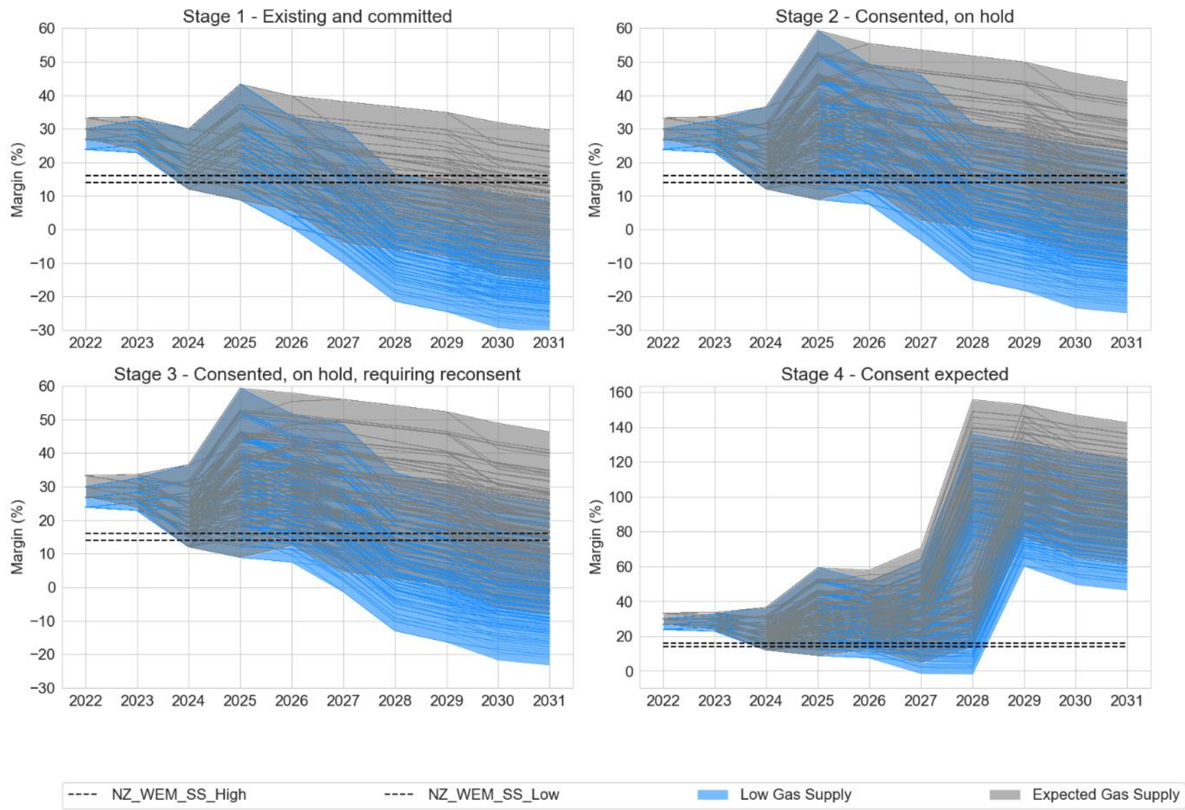


Figure 16: New Zealand Winter Energy Margin Delayed Build Times Sensitivity

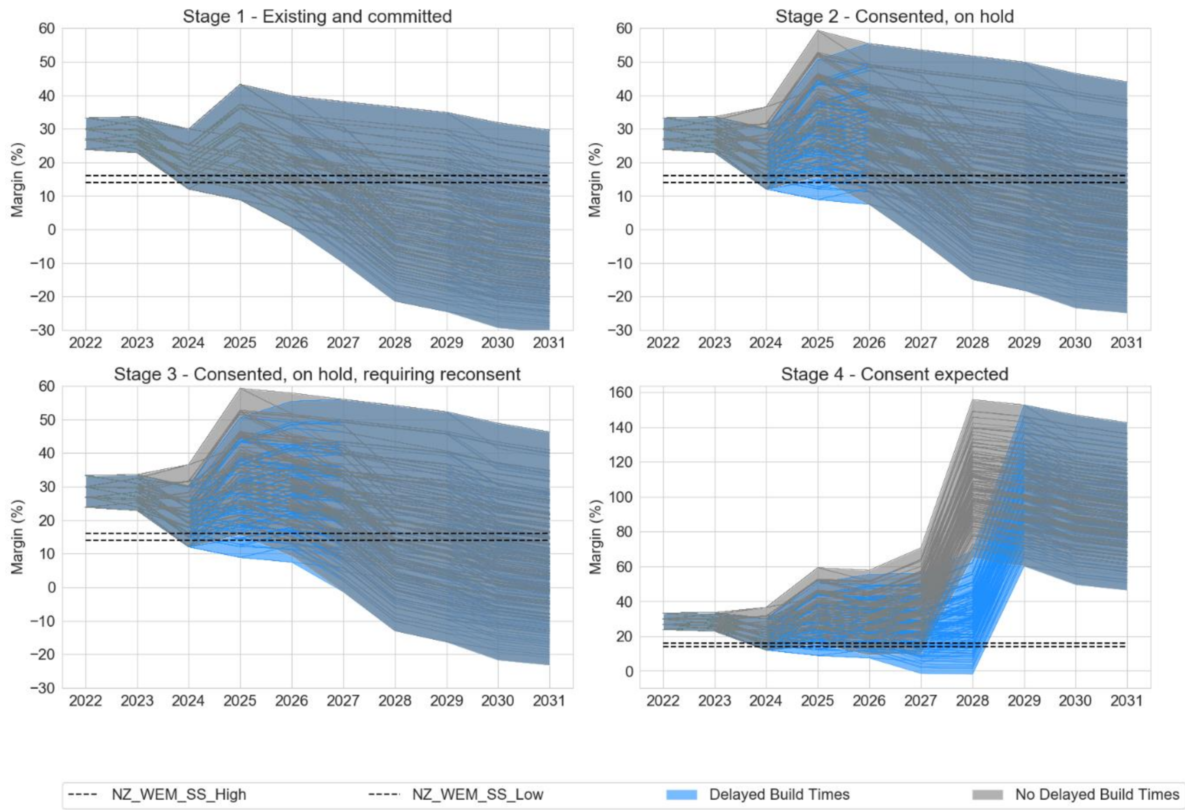
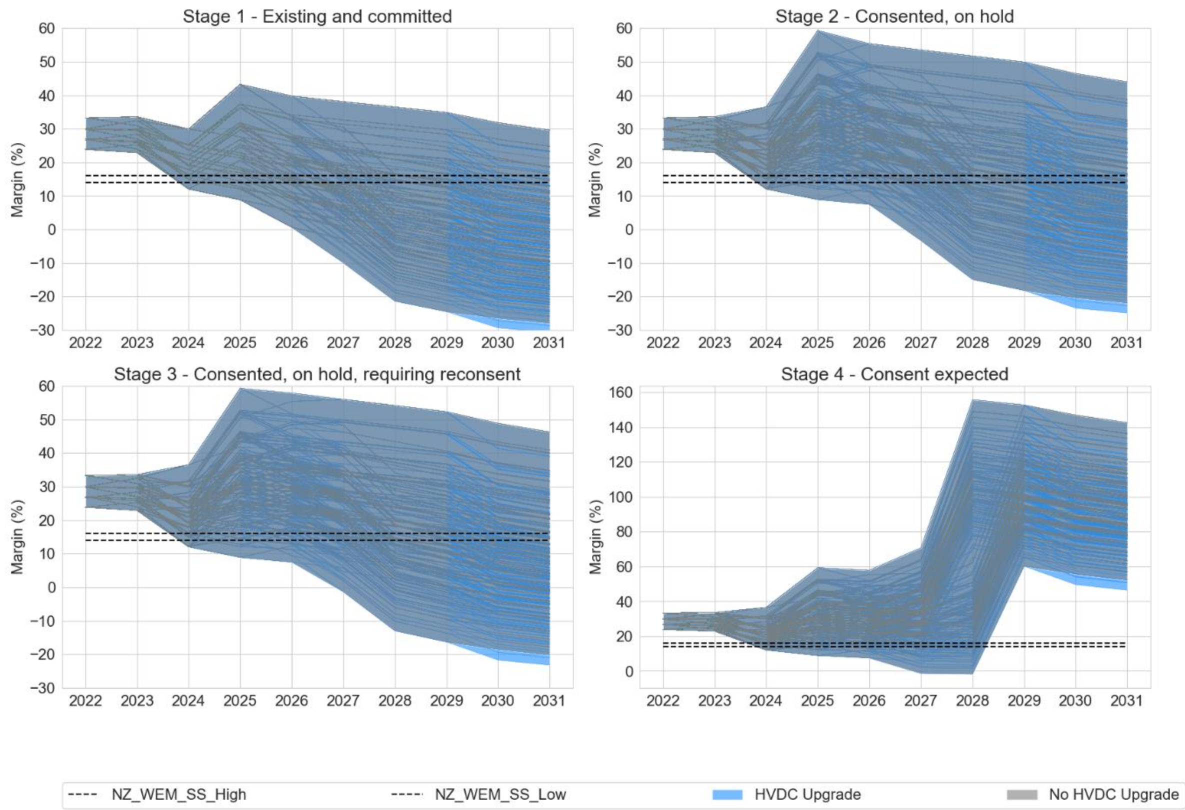


Figure 17: New Zealand Winter Energy Demand HVDC Upgrade Sensitivity



6.2 New Zealand Winter Energy Margin Demand Sensitivities

Figure 18: New Zealand Winter Energy Margin Demand Growth Sensitivity

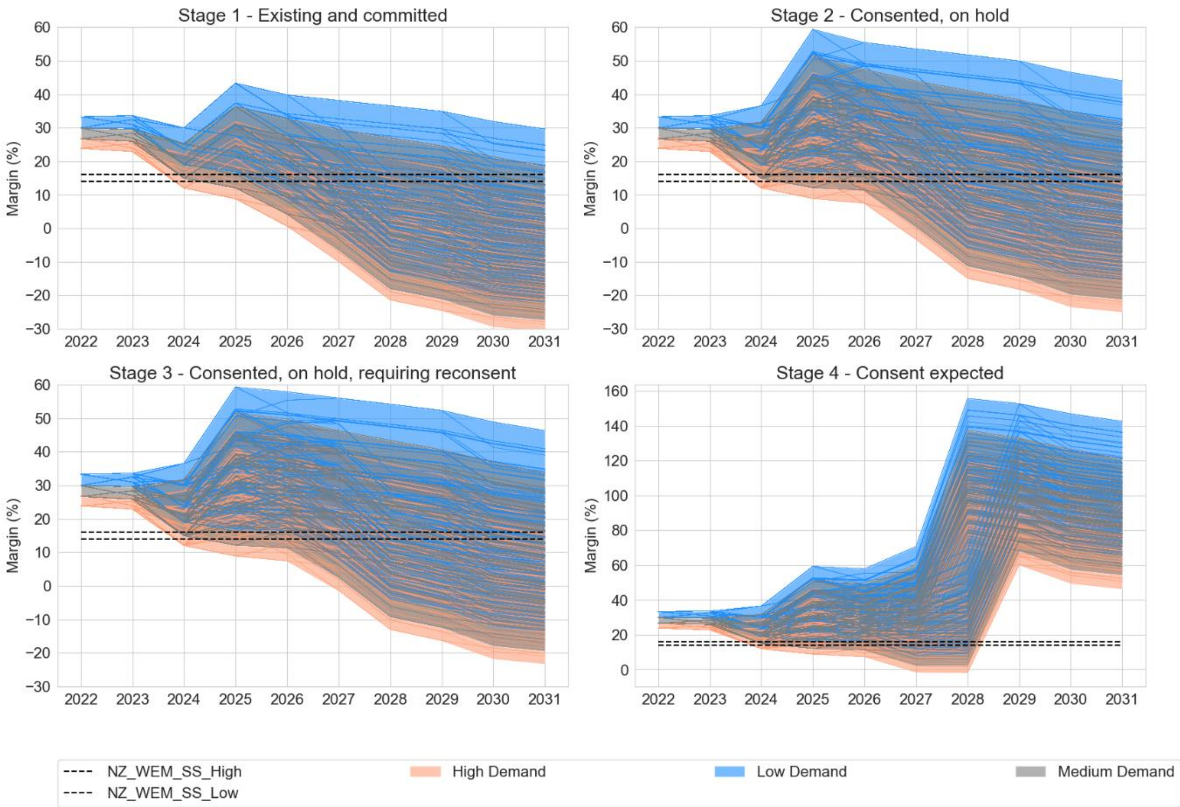


Figure 19: New Zealand Winter Energy Margin Tiwai Exits Sensitivity

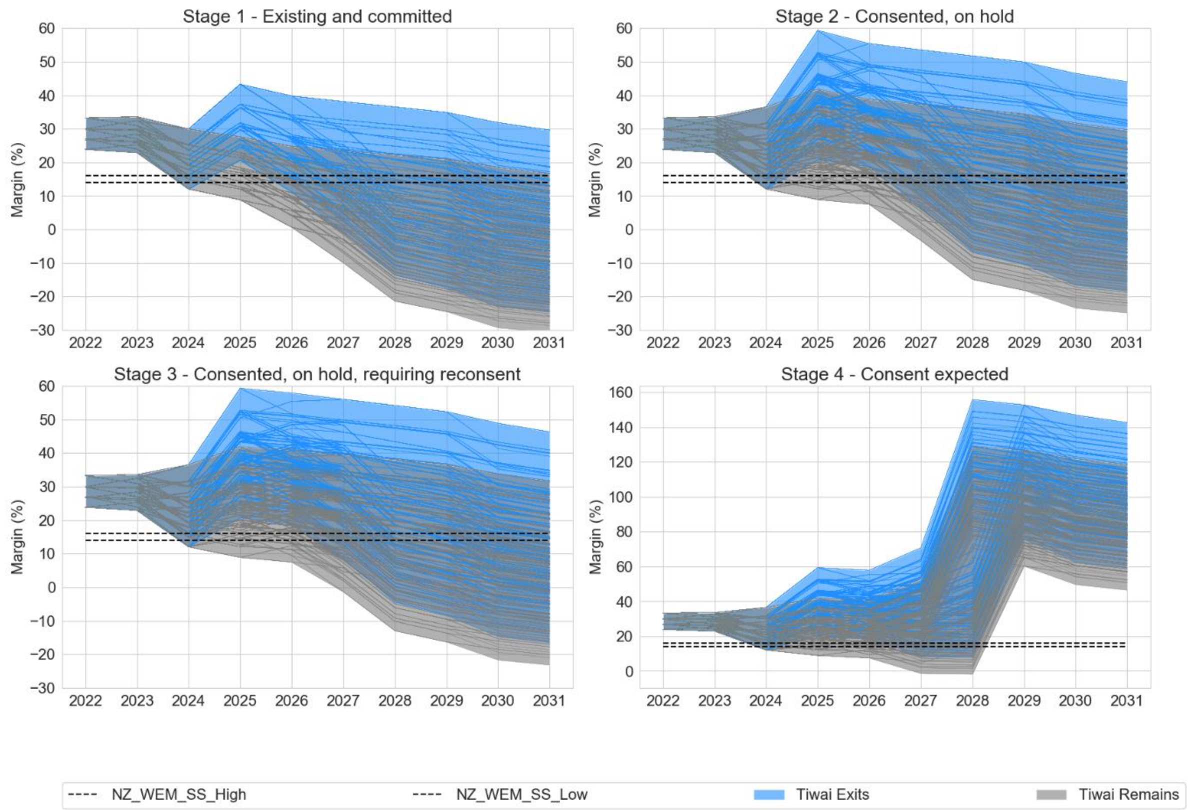


Figure 20: New Zealand Winter Energy Margin Step Change Increase in Demand Sensitivity

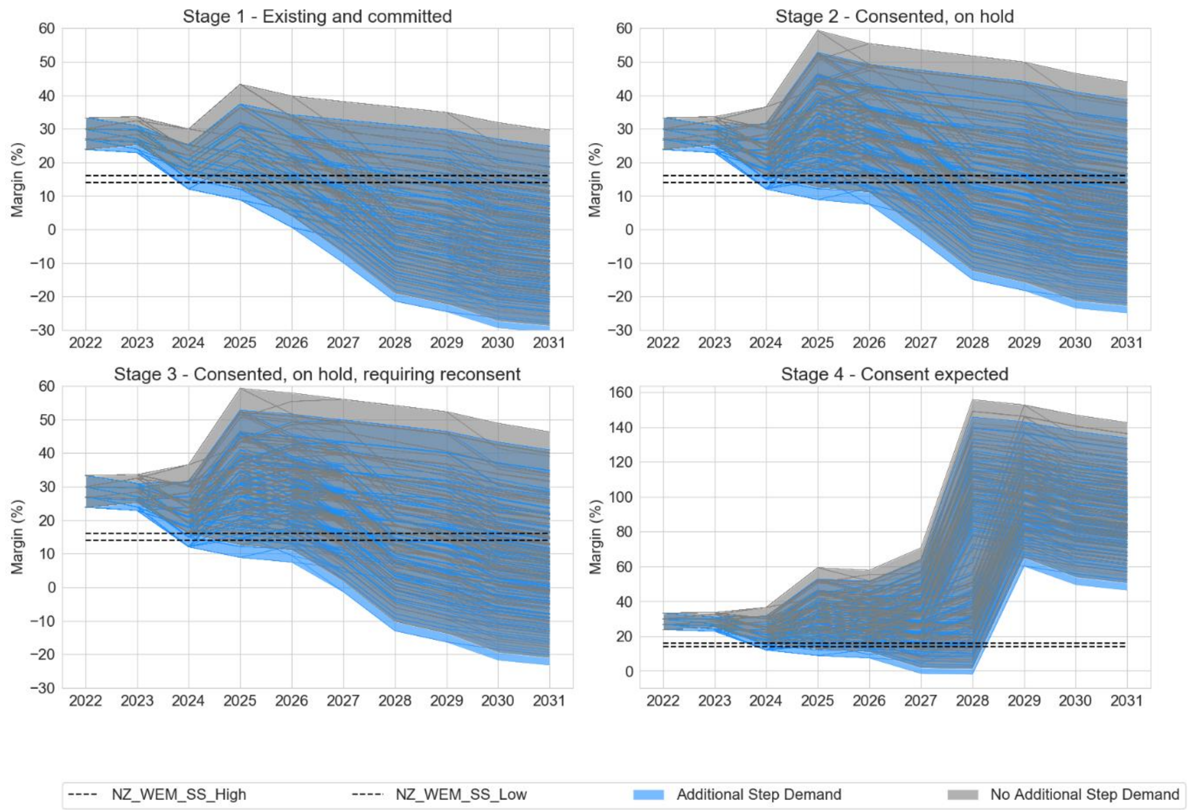
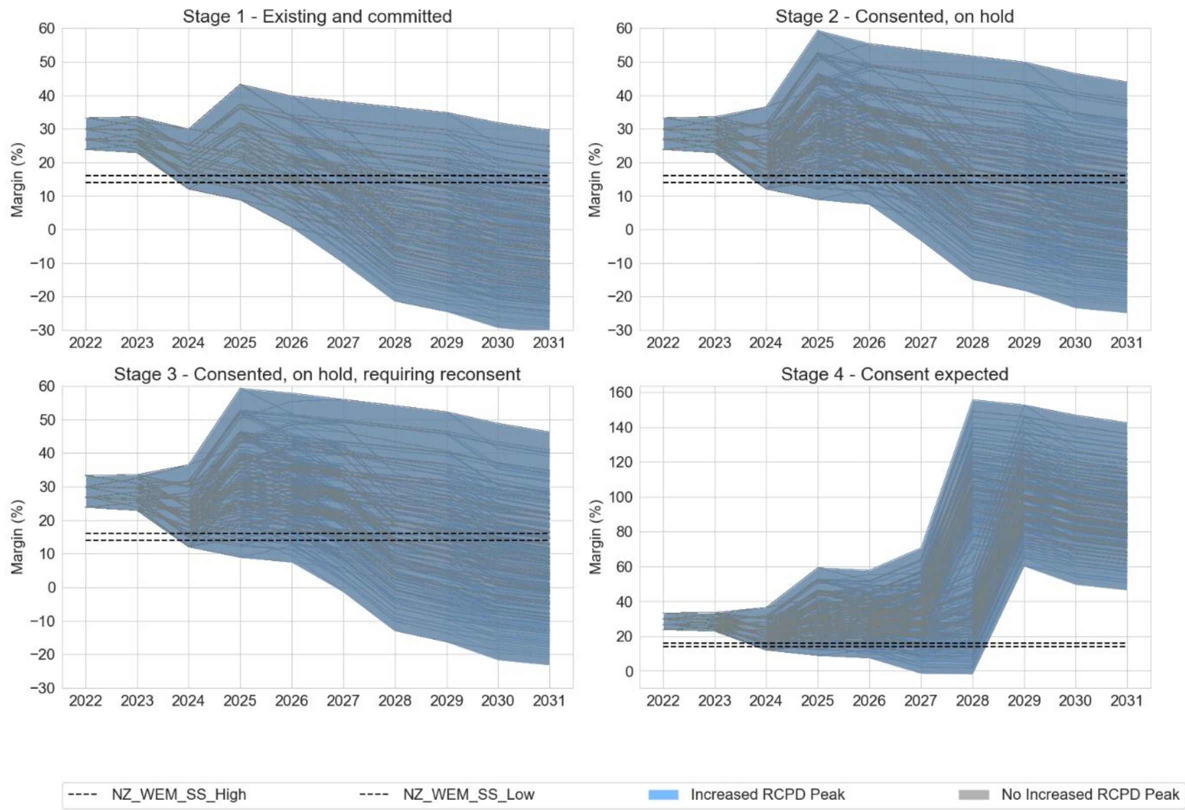


Figure 21: New Zealand Winter Energy Margin Change in Peak Transmission Pricing Sensitivity



6.3 North Island Winter Capacity Margin Supply Sensitivities

Figure 22: North Island Winter Capacity Margin Thermal Decommissioning Sensitivity

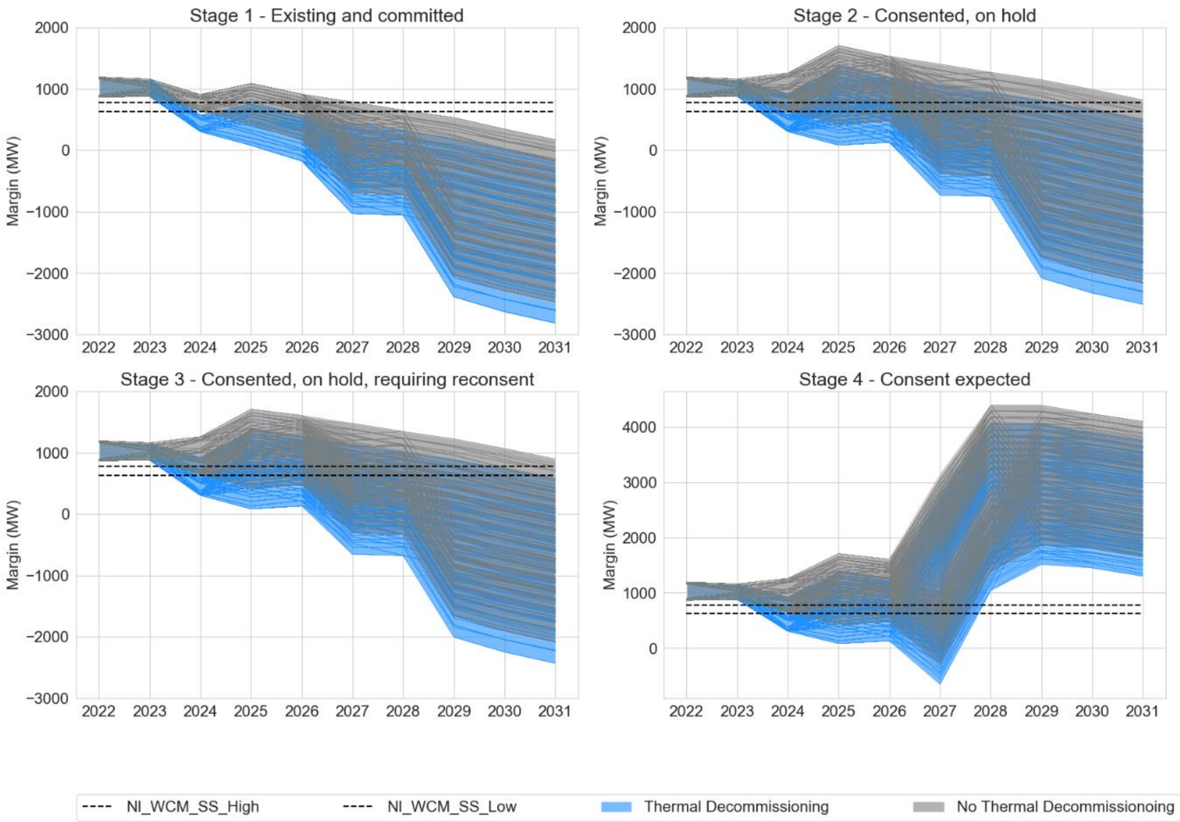


Figure 23: North Island Winter Capacity Margin Dry Year Reserve Sensitivity

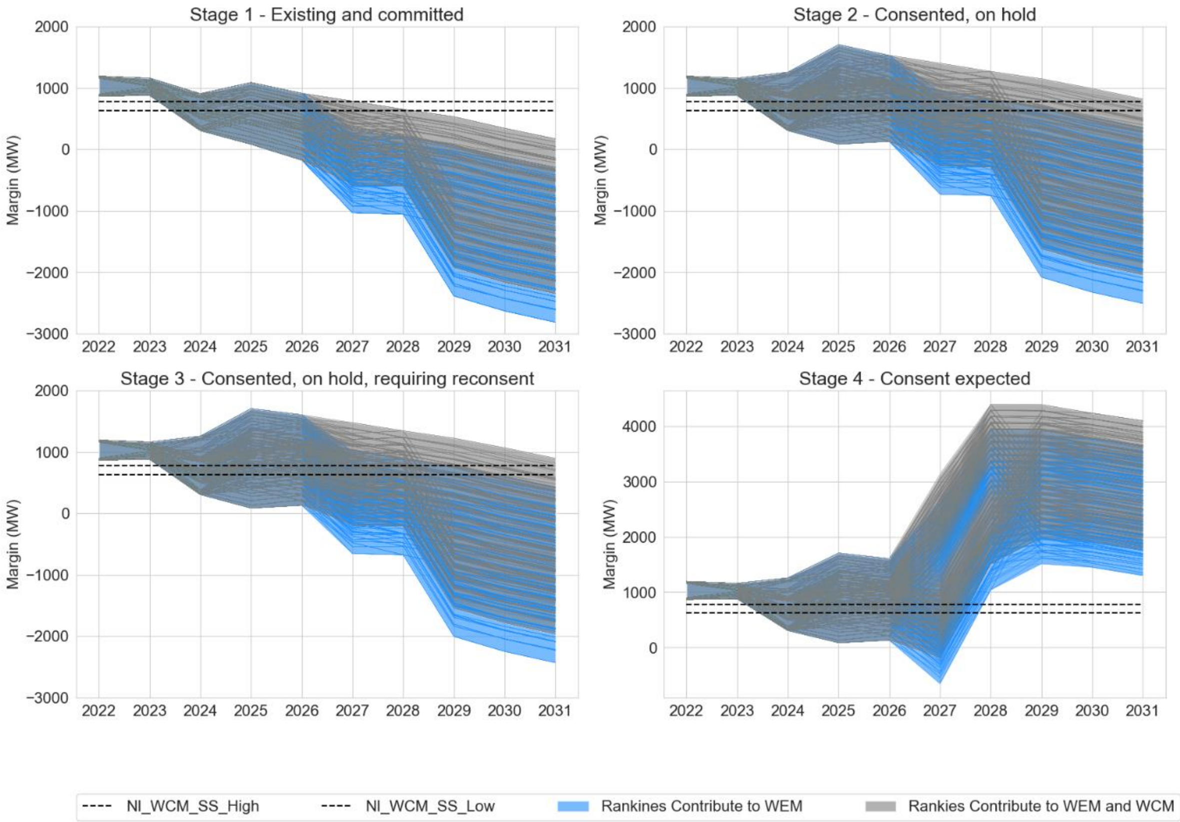


Figure 24: North Island Winter Capacity Margin Low Gas Sensitivity

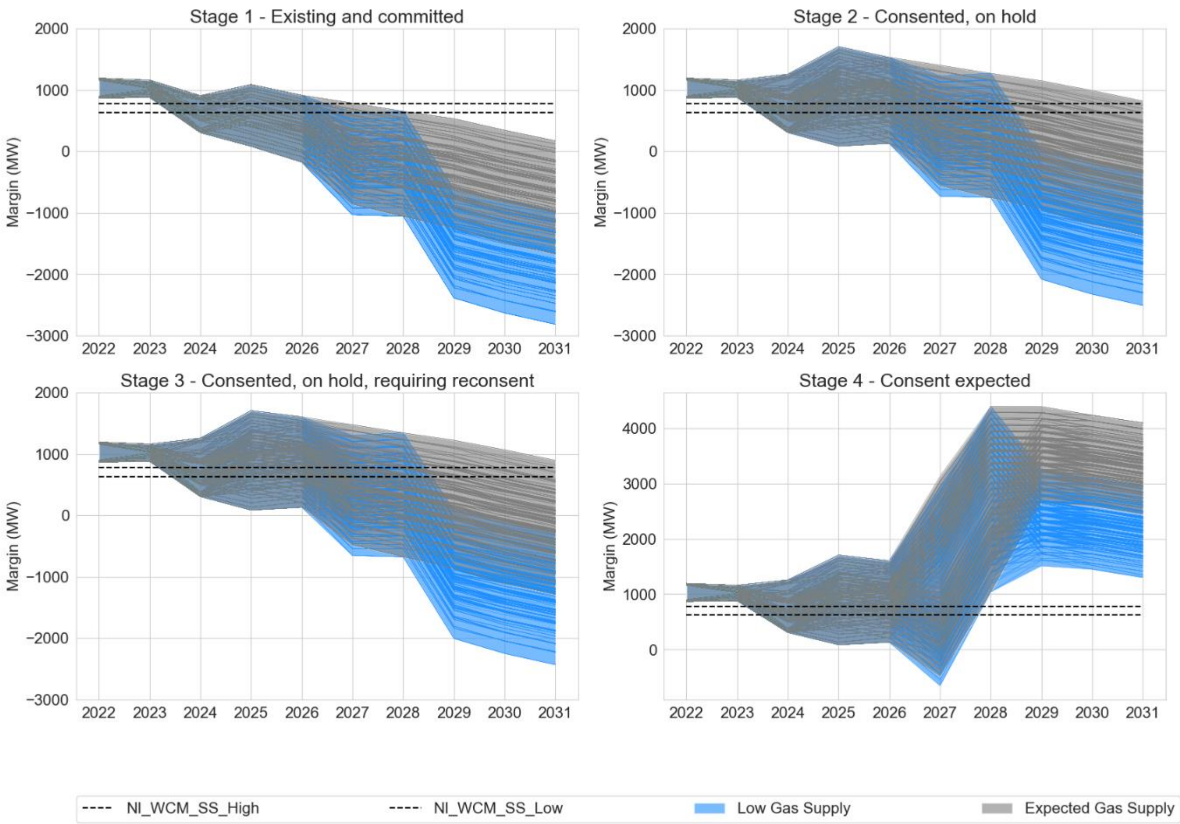


Figure 25: North Island Winter Capacity Margin Delayed Build Times Sensitivity

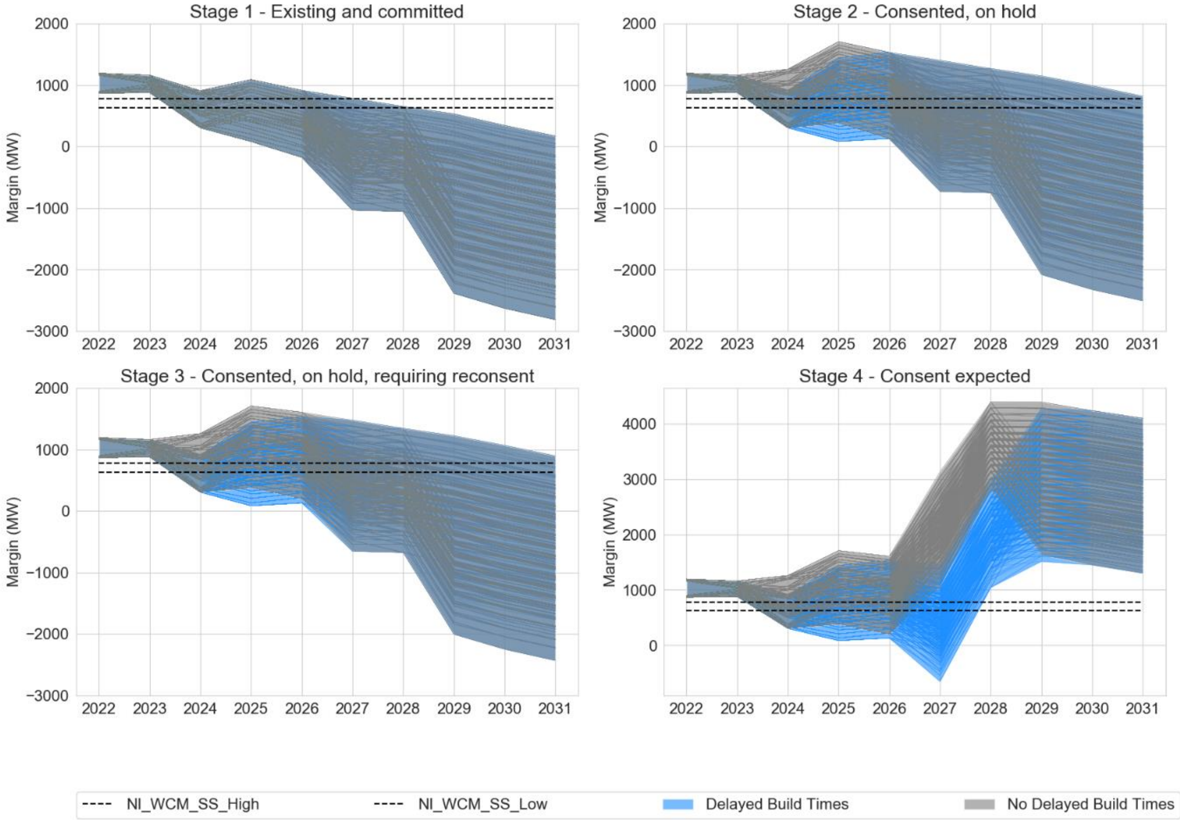
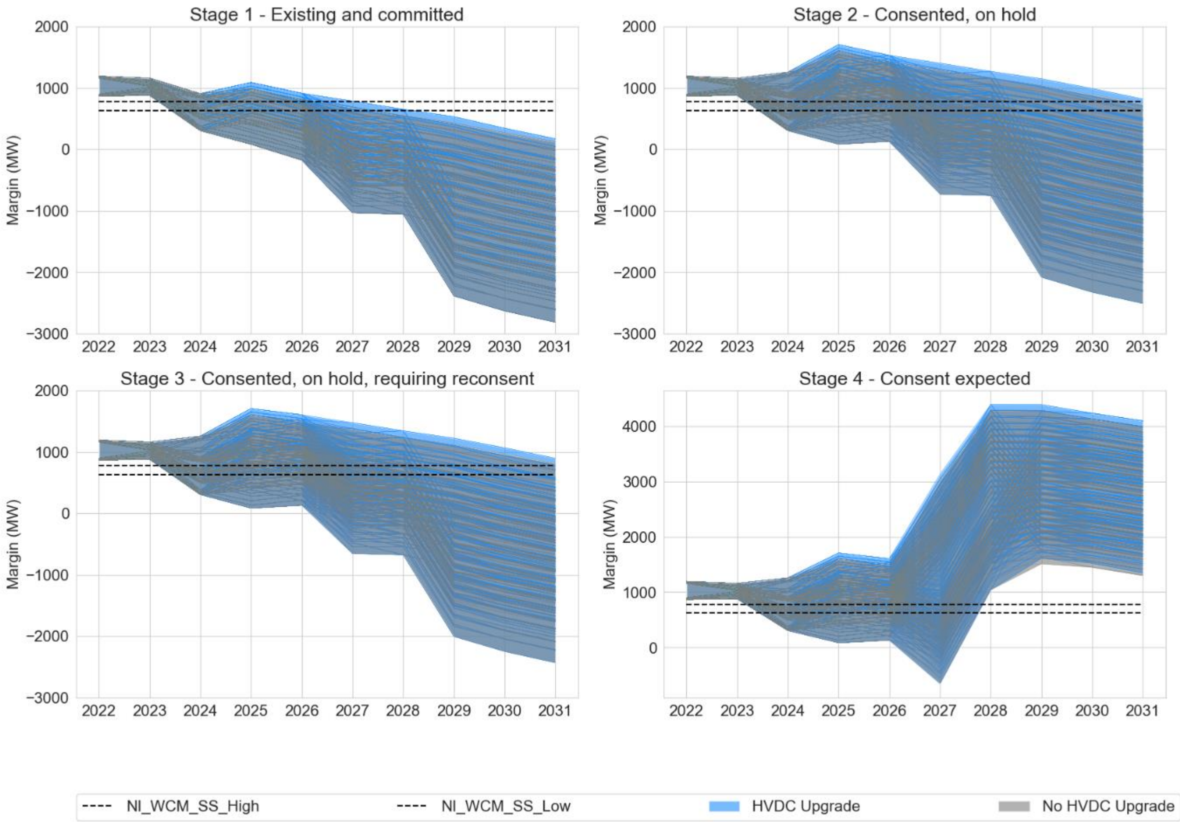


Figure 26: North Island Winter Capacity Margin HVDC Upgrade Sensitivity



6.4 North Island Winter Capacity Margin Demand Sensitivities

Figure 27: North Island Winter Capacity Margin Demand Growth Sensitivity

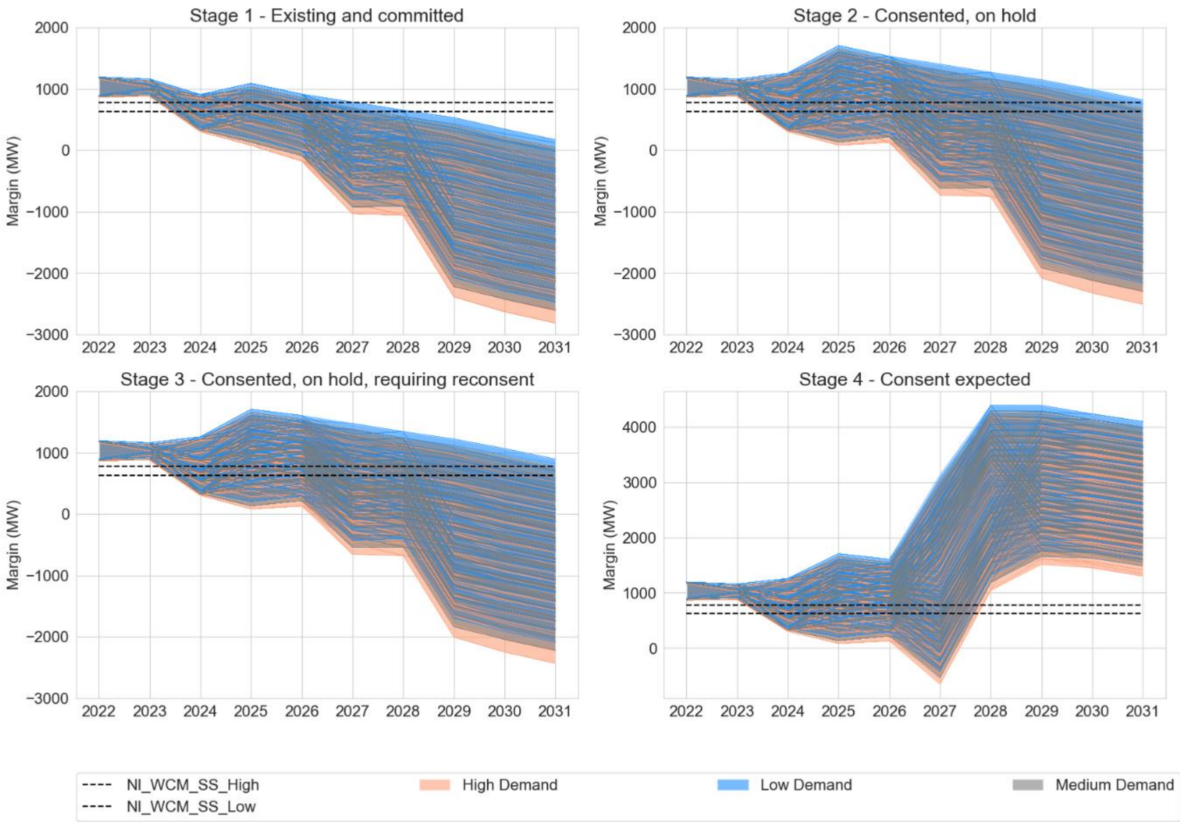


Figure 28: North Island Winter Capacity Margin Tiwai Exits Sensitivity

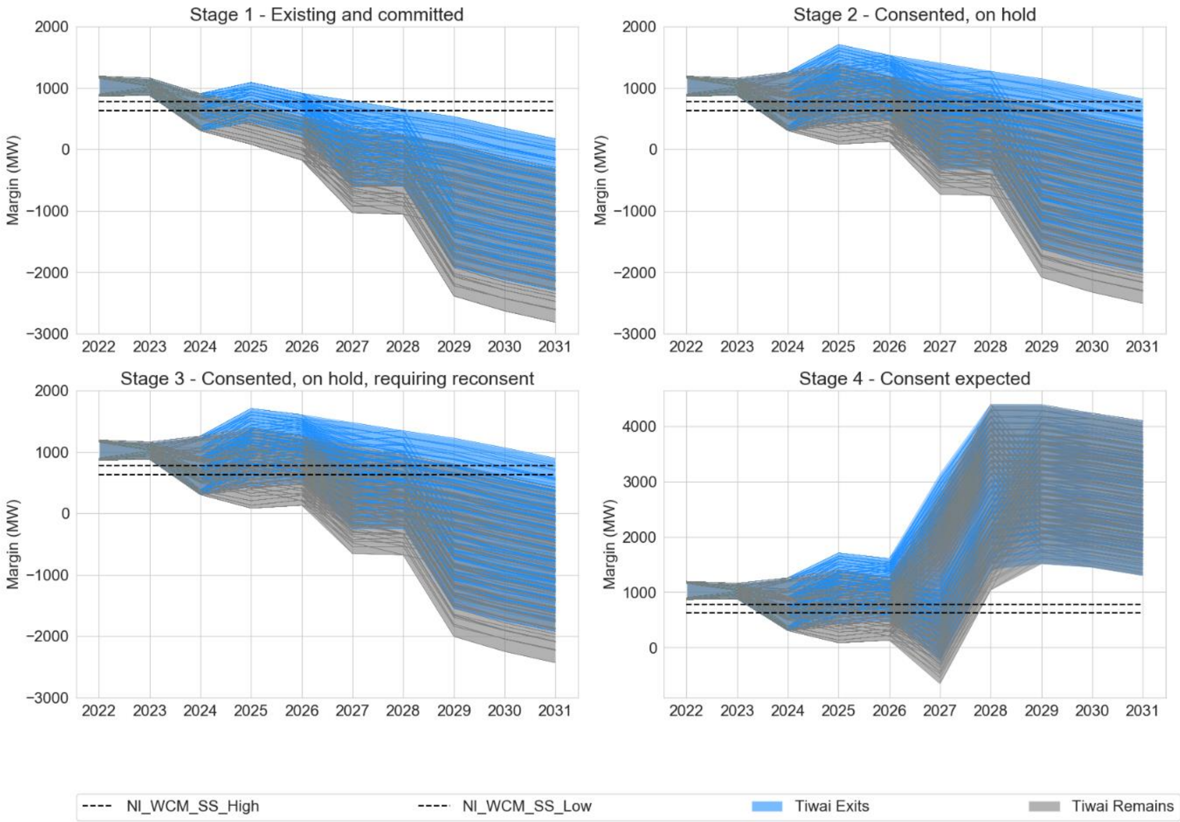


Figure 29: North Island Winter Capacity Margin Additional Step Demand Sensitivity

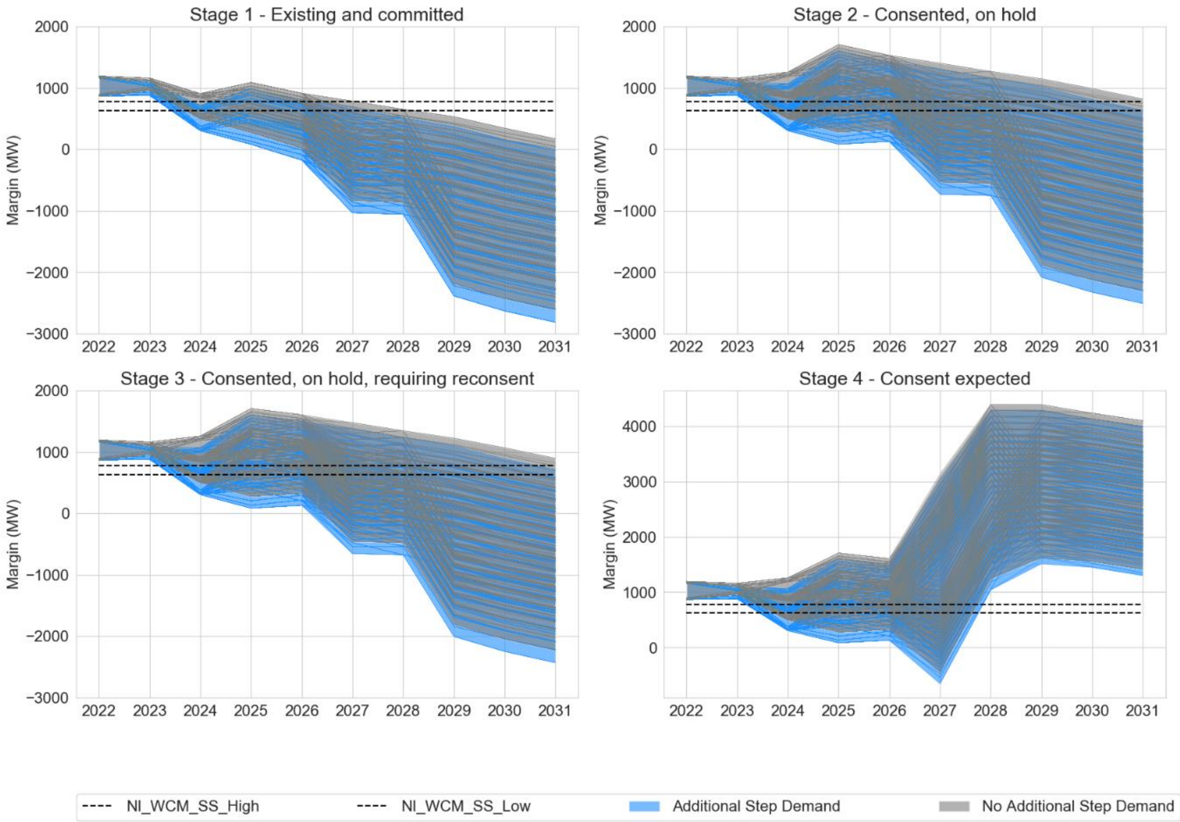
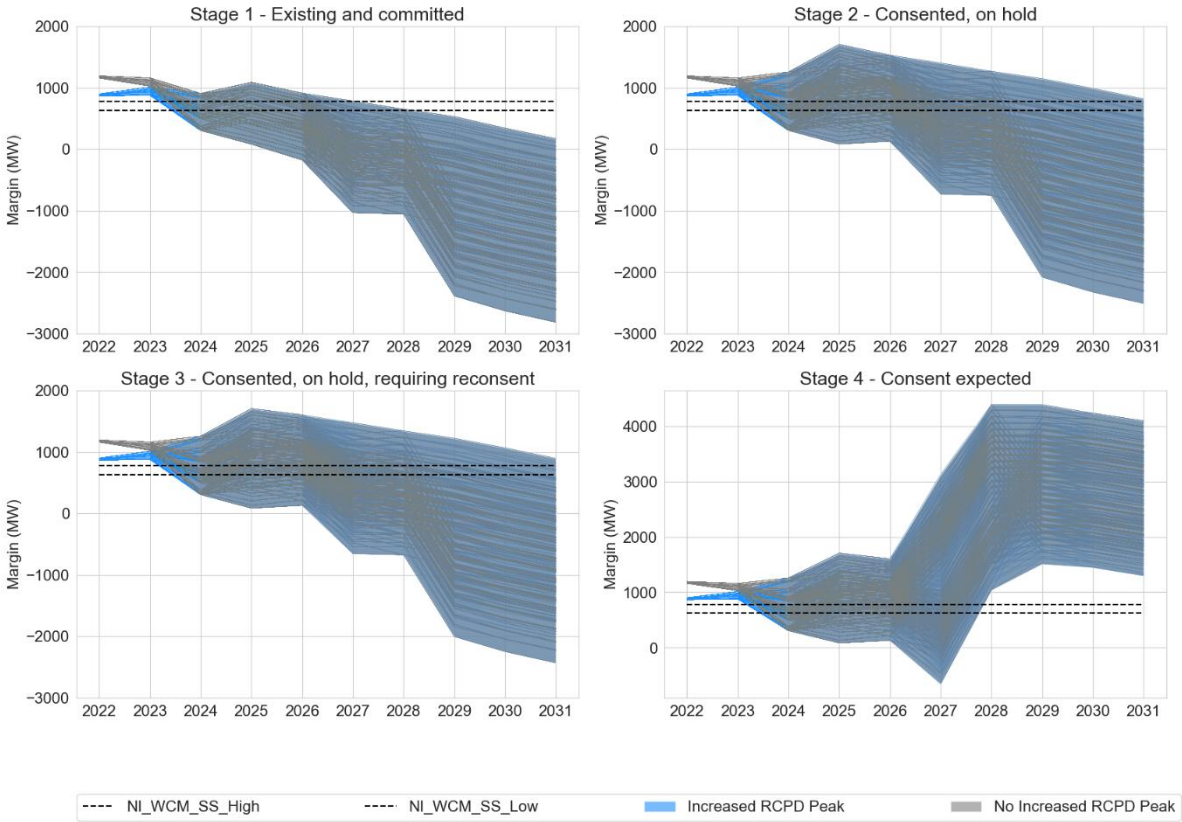


Figure 30: North Island Winter Capacity Margin Change in Peak Transmission Pricing Sensitivity



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