Stress testing regime – stress tests

Base case, stress tests and applications notes

Published under clause 13.236D of the Electricity Industry Participation Code 2010 (Code)

Effective from 11 November 2025

Contents

1. Purpose

Introduction

1.1 In November 2011 the Electricity Authority Te Mana Hiko (Authority) gazetted amendments to the Electricity Industry Participation Code 2010 (Code) to introduce a stress testing regime (referred to in the Code as Spot Price Risk Disclosure).

1.2 Clause 13.236D of the Code requires the Authority to publish a notice setting out:

(a) a base case

(b) one or more stress tests

(c) one or more methods for calculating a disclosing participant's actual and target cover ratio.

1.3 This document has been through a series of reviews to ensure the methodology is fit for purpose, and easy to apply, in an evolving market.

1.4 This version, effective from 11 November 2025, clarifies that the capacity shortage stress test spot price is not incremented by CPI.

Purpose of this document

1.5 This document sets out the information required by the Code and provides direction to relevant participants on how to apply the stress tests.

1.6 Further background information on the stress testing regime is available on the Authority's website at https://www.ea.govt.nz/industry/wholesale/spot-market/stress-tests/.

Structure of this document

1.7 This document provides direction under the following headings:

- Overview for application of stress tests
- Data for out-of-schedule stress test under clause 13.236G(1) of Code
- Stress test timeframes
- Electricity spot prices
- Electricity demand
- Hedging issues
- Electricity generation levels
- Cover ratios

2 Application of stress tests

Overview for application of stress tests

2.1 Despite the introduction of the stress testing regime, participants retain full responsibility for making decisions on their level of exposure to spot prices, and for managing that exposure on an ongoing basis.

2.2 The stress tests are not intended to be a complete test of disclosing participants' positions, but rather encourage disclosing participants to consider both their absolute and relative exposure to spot prices. The stress test scenarios do not represent likely, or necessarily extreme, scenarios.

2.3 For this reason, the stress testing regime is intended to dovetail as far as possible with the arrangements that participants will already have in place for monitoring exposure to spot price risk. In particular, the Authority has sought to limit the level of prescription in the stress testing arrangements as far as possible, while still ensuring that disclosure is robust.

2.4 Application notes are in three broad categories:

- quantitative assumptions – where the Authority specifies matters that must be followed. These relate primarily to the average price projections to be used in base case and stress test scenarios
- methodological direction – where the Authority sets out a methodology that it expects participants to follow. For example, the broad approach to be used to convert scenario prices referenced at Otahuhu to other nodes where participants buy or sell electricity. In this category, the Authority publishes summarised quantitative information (eg, locational adjustment factors based on historic data) to save participants the task of recalculating estimates from raw data. Although the Authority expects most participants to use this summarised quantitative data, participants may generate their own data provided they remain consistent with the broad approach specified by the Authority. For example, a participant may have access to more detailed historic information than the Authority, and could use that information in preparing its own projections
- qualitative direction – where the Authority provides direction of a non-quantitative nature. Participants must compile bona fide estimates consistent with this direction.

2.5 Table 1 provides a summary of the matters on which the Authority provides direction and the nature of that direction. The price requirements will be relevant to all disclosing participants, but other direction will only be relevant if operations extend into specific areas (demand, hedging or generation).

2.6 Direction being provided by the Authority is discussed in more detail in the following sections.

Table 1 Overview of direction for stress tests and base cases

		Energy shortage stress		Capacity shortage stress	
		Stress test	Base case	Stress test	Base case
Price issues	Average price levels				
Demand issues	Participant overall level of demand				
	Demand shape for forecastable demand				
	Demand shape for mass market load				
	Demand response (general)				
	Demand response (public conservation campaign)		n.a.	n.a.	n.a.
Hedge issues	Firm hedging arrangements				
	Contingent hedging arrangements				
Generation issues	Hydro inflow levels			n.a.	n.a.
	Opening and closing hydro storage levels			n.a.	n.a.
	Hydro generation levels				
	Wind generation levels				
	Thermal/geothermal levels				
Other	Cover ratios				

Data for out-of-schedule stress test under clause 13.236G(1) of Code

2.7 If an additional stress test is requested that occurs within the quarter it applies to, it may be possible to use actual data for the earlier portion of the quarter, rather than relying on forecasts. Disclosing participants should take all reasonable steps to include such actual data.

2.8 Unless otherwise specified, it is only necessary to apply stress test scenarios from the date of the announcement of the out-of-schedule stress test.

2.9 In particular, participants should assume that elevated prices in an energy stress scenario only apply for future days in the quarter.

Stress test timeframes

2.10 The stress test regime applies to the next 12 quarters. An in depth set of tests are required for the immediate quarter, while the following 11 quarters have a simpler and separate methodology. This is detailed in the ‘Cover ratios’ section.

2.11 The stress tests also require the disclosing participant to provide information on the previous quarter, which will allow comparison between expected hedge cover and actual hedge cover. This is also detailed in the ‘Cover ratios’ section.

Electricity spot prices

2.12 The spot price assumptions in the base cases and stress tests are specified in base load equivalent terms.

General principle

2.13 The Authority requires all disclosing participants to operate with common assumptions about spot price outcomes in the base case and stress test scenarios. For this reason, it has provided direction on spot price projections.

Specific direction

2.14 The Authority requires that disclosing participants comply with the following:

2.15 To calculate the effect of the base case and stress tests on their operations, each participant must use spot price projections that are relevant to their operating locations if the prices at the operating locations are materially different from the price set in Appendix B. If the participant uses different spot price projections, it must keep a record of why it has used a different spot price projection and how it has calculated its spot price projection.

2.16 If a participant uses a different methodology, it should use the Regional TOU factors, Nodal factors, and Demand factors (as applicable to the type of stress test) published by the Authority on its website.[1] If a participant chooses to use other adjustment factors in its methodology, it must keep a record of its reasons.

2.17 If a participant uses different spot price projections, it must apply this methodology consistently from quarter to quarter and keep a record of the reasons if it changes its methodology.

2.18 A separate energy related stress test price is set for the North Island and the South Island. To ensure prices remain relevant, a 2% increase (compounded) will be applied to energy prices using 2025 as the base year. Table 5 of Appendix B sets out these prices for the next 10 years. Capacity stress test prices are conceptually linked to scarcity pricing values in the Code. These do not increment annually therefore the capacity test does not have an annual price adjustment.

Electricity demand

2.19 Disclosing participants must estimate their electricity demand to calculate their projected wholesale electricity purchase costs in the base case and stress test scenarios. These estimates must account for locational and load shape issues, to the extent they have a material effect on wholesale electricity purchase costs. Demand estimates must also take account of demand response in the stress test scenarios, where this is appropriate.

General principle

2.20 Each disclosing participant has a unique demand profile, which reflects the specific characteristics of its operations. For this reason, other than the specific areas of direction set out below, disclosing participants are responsible for estimating their demand, subject to a general requirement that the results should reflect bona fide estimates of outcomes expected in the base case and respective stress test scenarios. This means the estimates should be based on the actual demand for the same quarter in the previous year and adjusted for issues such as:

- changing trends in the sources of demand
- commitments that alter demand from existing levels (eg, customer acquisition campaigns, expected changes to production levels)

[1] https://www.ea.govt.nz/documents/2013/Stress_testing_-_quantitative_data.xlsx

- seasonal factors that exhibit a relatively predictable pattern.

2.21 For a new entrant to the market with less than 12 months of historical demand, the participant must use its actual known demand and adjust it for the participant's growth strategy.

2.22 The Authority recognises this approach provides participants with a degree of discretion. However, it notes spot price risk disclosure statements are subject to independent audit if required by the Authority.

Specific direction

2.23 The Authority provides the following specific direction to disclosing participants:

Demand shape for capacity-related stress tests

2.24 The capacity-related stress tests assume the adverse event coincides with a period of New Zealand peak system demand for the relevant quarter[2].

2.25 Disclosing participants with specific knowledge of their underlying electricity demand sources (eg, major users) must estimate their projected load at such a time. This will constitute the demand estimate for both the base case and stress test scenarios (unless there is demand response in the latter – see below for further discussion).

2.26 Disclosing participants without specific knowledge of their underlying electricity demand sources (eg, retailers serving mass market customers) must estimate their projected load based on the projected average half-hourly load for the quarter, multiplied by an adjustment factor to reflect load shape at the time of system peak.

2.27 The Authority has estimated adjustment factors based on historic data[3] and these are available in Table 2.

Table 2

	Q1	Q2	Q3	Q4
NI	125%	135%	130%	125%
SI	120%	125%	125%	120%

Demand response levels and costs

2.28 In compiling load estimates for stress test cases, disclosing participants must incorporate the effect of demand response mechanisms where these can be relied upon with a high degree of assurance (eg, due to direct control, contractual mechanisms, or based on demonstrated past experience).

2.29 Where demand response is assumed, it must take account of any factors that constrain or limit its effectiveness. For example, in the context of capacity-related stress tests, if a demand response

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2 In this context the peak demand is equal to the average demand over eight hours (8.00am to12.00pm and 5.00pm to 9.00pm) in two consecutive days. The demand level has been measured over the highest New Zealand peaks in each quarter over the last 12 years.

3 The calculated peak factors have been derived for total demand from the national grid (excluding direct connected customers where these can be identified easily) in a number of regions. The regions are consistent with those used in the Electricity Commission 2010 Statement of Opportunities. The published table summarises the factors for the North and South Islands.

mechanism requires two hours to activate, then a demand response must not be assumed during the first four trading periods of the stress test.

2.30 If demand response results in any change in costs or revenues relative to the base case for the disclosing participant, this must be taken into account when calculating the projected net cashflow from operating activities for that relevant stress test scenario. For example:

a. a retailer's costs could increase if it is required to make payments to downstream electricity customers when demand response is activated; or

b. an electricity user's net sales revenues may be lowered by reduced production levels.

Demand growth

2.31 For the 11 quarters beyond the immediate quarter, disclosing participants must use customer acquisition/growth levels from the same quarter from the previous year. For example, if calculating quarter 3 for 2026, a disclosing participant would use quarter 3 2025 customer acquisition/growth rates.

Hedging issues

2.32 Disclosing participants must account for the effect of hedge contracts (electricity price risk management contracts) when estimating their projected net cash flows from operating activities in the base case and stress test scenarios.

General principle

2.33 Hedging arrangements take a wide variety of forms. For this reason, other than the specific direction set out below, disclosing participants are responsible for estimating the impact of hedge contracts on their cash flows, subject to a general requirement the results must reflect bona fide estimates of outcomes expected in the base case and respective stress test scenarios.

Specific direction

2.34 The Authority requires disclosing participants comply with the following:

Degree of firmness of hedge arrangements

2.35 Where disclosing participants have a firm hedging arrangement with an external party under which they are obliged to make, or can claim, payments which vary depending on spot price outcomes, then the effect of this arrangement must be accounted for when calculating projected net cash flows from operations.

2.36 Where disclosing participants do not have a legally enforceable hedging arrangement (eg, because discussions about a prospective contract have not yet been concluded), the arrangement must not be taken into account when calculating projected net cash flows from operations.

2.37 These principles apply to arrangements that mitigate all forms of spot price risk, including locational price risk (eg, financial transmission rights). If a participant is not using location (nodal) factors in its calculation of spot price, FTR payments should not be taken into account.

Contingent arrangements

2.38 Some arrangements contain provisions where the hedging effect is contingent on market conditions or the actions of a party. For example, an arrangement may require one party to give prior notice it wishes to invoke a cap contract, and the hedging effect comes into operation after the notice period.

2.39 Disclosing participants that have provided such options must assume counterparties exercise these options if they confer a financial benefit on that counterparty in the relevant base case or stress test (and vice versa). Similarly, disclosing participants that have the ability to exercise such options must include their effect when calculating net cash flows from operations if they consider the option would be exercised in the relevant base case or stress test scenarios.

Availability of Financial Transmission Right (FTR) payments

2.40 If a participant is using its own calculation methodology for spot price, the participant should consider whether the FTR Rentals Amount is likely to exceed the loss and constraint excess (ie, it is 'revenue inadequate', so payments are scaled) in the specified stress test and how this will affect any FTR payments they will receive.[4]

Electricity generation levels

2.41 To calculate the effect of the stress tests on their positions, disclosing participants with generation resources must estimate their production levels for the base case and stress test scenarios.

General principle

2.42 Each disclosing participant with generation will have detailed information about the assets under its control. For this reason, other than the specific areas of direction set out below, disclosing participants are responsible for estimating their projected generation levels, subject to a general requirement the projections must reflect bona fide estimates of outcomes expected in the base case and respective stress test scenarios. This means the estimates must take account of issues such as:

a. availability of thermal fuel supplies

b. any expected transmission constraints likely to affect output levels

c. planned changes in plant availability.

2.43 The Authority recognises this approach provides participants with a degree of discretion. However, it notes spot price risk disclosure statements are subject to independent audit if required by the Authority.

Specific direction

2.44 The Authority requires disclosing participants comply with the following:

Hydro inflow levels for energy-related tests

2.45 For the base case, disclosing participants with hydro generation must assume mean inflows into their catchments based on historic data for the relevant quarter. This ensures broad consistency between assumed hydro inflows and spot prices in the base case.

2.46 For the stress tests, projected inflows for hydro generation catchments must be calculated using the relevant adjustment factors found in Table 3 against base case inflows.

[4] See section 2.8 of "FTR Allocation Plan 2017"

Hydro generation starting storage for energy-related tests

2.47 For the base case, disclosing participants with hydro generation must assume their storage reservoirs are at the relevant mean level for the beginning of the coming quarter. This reflects the base case assumption that spot prices are at a broadly 'normal' level, irrespective of prevailing conditions (whether wet or dry). Projected starting storage levels for the main controlled reservoirs have been estimated from historical data and these are published in spreadsheet form on the Authority's website.

2.48 For the stress test scenarios, disclosing participants with hydro generation must assume their storage is at prevailing levels, adjusted for any expected change between the date of the estimate and the beginning of the relevant quarter (which must be no more than 20 working days and no less than five working days later).

Hydro generation closing storage for energy-related tests

2.49 For the base case, disclosing participants with hydro generation must assume their storage reservoirs track to the mean closing level for the quarter.[5] Again, this reflects the base case assumption spot prices are at a broadly 'normal' level, irrespective of prevailing conditions (whether wet or dry).

2.50 For the stress test scenarios, disclosing participants with hydro generation must assume their closing storage is no less than their legal or operational limit, whichever is higher.

Wind generation levels for energy-related tests

2.51 For the base case, disclosing participants with wind generation must assume mean output levels based on historic data for the relevant quarter. This ensures that generation levels are broadly consistent with the spot price projection in the base case.

2.52 For the stress tests, projected wind generation levels must be calculated using the relevant adjustment factor in Table 3, against the base case generation.

Solar generation levels for energy-related tests

2.53 For the base case, disclosing participants with solar generation must assume mean output levels based on historic data for the relevant quarter. This ensures that generation levels are broadly consistent with the spot price projection in the base case.

2.54 For the stress tests, projected solar generation levels must be calculated using the relevant adjustment factor in Table 3 against the base case generation.

Table 3 Adjustment for generation against the base case

% of mean	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Hydro	30%	35%	30%	30%
Wind	80%	80%	80%	80%

5 The Authority has published average storage levels for the main reservoirs at the start of each quarter. The average closing level for any quarter is the same as the average starting level for the following quarter.

Solar	90%	90%	90%	90%

Generation levels for capacity-related tests

2.55 For the base case, disclosing participants with generation sources must estimate their projected output based on expected levels during a period of high demand for the respective quarter. In the case of non-controllable generation (eg, wind, solar and run of river hydro), disclosing participants must assume average levels of production for the relevant time of year.

2.56 For a capacity stress test, participants with controllable batteries with more than 1MWh of storage capacity must assume the batteries are charged to 50% of maximum capacity at the start of the stress test and discharge at the maximum discharge rate until they are fully discharged.

2.57 For a capacity stress test without additional forced generation loss (ie, loss of large thermal units or wind generation), generation levels for non-controllable generation must be the same as the base case. Disclosing participants with controllable generation sources (eg, thermal and hydro dependent on storage reservoirs) must adjust projected generation levels to reflect their expected response during a capacity shortage. This adjustment must reflect any factors that would limit the amount or rate of increase of generation during an unexpected sudden capacity shortage. For example, this would include issues such as delays in starting uncommitted thermal units, releasing stored water for use in downstream generation etc.

2.58 For any capacity test with additional forced generation loss, disclosing participants that included generation from a thermal unit of 200 MW or more in the base case must assume zero generation from their largest thermal unit during the stress test period. Likewise, disclosing participants that included wind generation in the base case must assume that their largest wind farm has zero generation during the stress test period. If a disclosing participant has generation from both a large thermal unit and a wind farm in the base, it must assume that the larger of the two sources (in average output terms) has zero generation in the stress test.

Cover ratios

2.59 The Code requires disclosing participants to state whether or not they have an explicit risk management policy in respect of exposure to the wholesale market. If participants have an explicit policy, they must disclose their actual and target cover ratios for each stress test calculated in accordance with the method publicised by the Authority.

General principle

2.60 The “target cover ratio” concept is intended to reflect a participant’s preferred level of hedge cover, as recorded in its risk management policy documents, rather than the actual level of cover at the time the stress tests are applied.

2.61 Where a participant has an explicit risk management policy that is already framed in ratio terms, it should be relatively straightforward to calculate a target cover ratio. However, the Authority recognises some participants may not have an explicit risk management policy. Further, even where there is an explicit policy in place, it may not be possible to calculate a meaningful target cover ratio in some cases. The notes take account of these different situations.

2.62 The “actual cover ratio” is the participant’s actual cover ratio for the quarter prior to the quarter in which the spot price risk disclosure statement is prepared and submitted. The Authority recognises that the information enabling the calculation of actual cover may not always exist (for example where a participant was not a disclosing participant for the prior quarter). Actual cover ratios therefore only need to be prepared where the information enabling their calculation does exist.

Specific direction

2.63 The Authority requires that disclosing participants comply with the following:

Method for calculating target cover ratio for the immediate quarter

2.64 If a participant has no explicit risk management policy, it must enter "not applicable" in the relevant sections of the disclosure statement.

2.65 In all other cases, the participant must calculate the target cover ratio, as the proportion of spot price payment obligations that, according to the explicit policy, must be covered by risk management mechanisms (whether physical or financial) that insulate the participant from spot price movements.

2.66 In this context, 'spot price payment obligations' includes payments to the clearing manager for wholesale market purchases, and any obligation to make a payment that moves with the spot price. For example, if a generator sold a fixed price hedge to a counterparty, it would have a payment obligation to that counterparty that is linked to the spot price.

2.67 'Risk management mechanisms' encompasses any arrangement or resource that reduces or offsets the participant's exposure to spot price movements. This includes financial hedges, generation resources and firm demand response arrangements.

2.68 If a major user has a policy of hedging at least 85% of its expected electricity purchases for the coming period with fixed price arrangements, it must disclose "0.85" as its target cover ratio (irrespective of its actual hedge position). If it has a policy targeting a range of hedge cover (eg, between 85% and 95% of purchases covered), the target cover ratio would be the mid-point of the values (eg, 0.9).

2.69 The spot price payment obligation for net sellers (ie, generators) in the spot market must be determined primarily by the hedges they sell. For example, if a generator has a policy of selling no more than 90% of firm generation capability on fixed price arrangements, it must disclose "0.9" as its target cover ratio, since the required proportion of risk management mechanisms (generation in this instance) to spot price payment obligations (hedge sales in this instance) is 0.9/1.

2.70 Where a participant's risk management policy is not expressed in a form that sets a minimum or expected level of forward cover, it will not be feasible to calculate a meaningful target cover ratio. For example, this would be the case where a risk management policy set a minimum earnings threshold that should be achieved with a predefined level of probability. Given the stress tests are not probabilistic in nature, it would not be possible to infer a target coverage ratio from a policy of this form.

2.71 In such instances, participants should enter "not feasible" in the Target Cover Ratio section of the disclosure form.

Method for calculating actual cover ratio for the past quarter

2.72 All participants are required to submit an actual cover ratio, covering the quarter prior to the quarter in which the spot price risk disclosure statement is prepared and submitted. For example, for stress test disclosures covering the 1 July to 30 September quarter, the actual cover ratio should be for the 1 January to 31 March quarter.

2.73 The Authority aims to make calculating actual cover ratios simple and are based on your previous quarter's performance. Disclosing participants that are predominantly net buyers in the spot market (ie, industry or retailers), should submit the percentage of the previous quarter's total demand that was covered by risk management contracts.

$$\frac{executed\ risk\ management\ contracts\ +\ generated\ electricity}{electricity\ demand}$$ [6]

2.74 For disclosing participants that are predominantly net sellers in the spot market (ie, generators), this will change slightly to the previous quarter's generation covered by risk management contracts.

$$\frac{executed\ risk\ management\ contracts + electricity\ demand}{electricity\ generation}$$ [6]

Method for calculating target cover ratio beyond the immediate quarter

2.75 For the additional 11 quarters a simpler target cover ratios calculation must be used. This is shown below:

$$\frac{purchased\ risk\ management\ contracts\ +\ physical\ resources}{sold\ risk\ management\ contracts\ +\ projected\ quarterly\ electricity\ demand}$$

2.76 All components of this formula are expressed as MWh. Physical resources should be calculated as set out in 2.44 through 2.58

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6 "Risk management contracts" means the net value of all risk management contracts purchased and sold that are calculated and settled during the quarter (including PPAs where you are not settling the physical electricity with the clearing manager). For contracts that are longer than the relevant quarter, only include the amounts that are settled during the relevant quarter.

"Generated Electricity" means the total electricity you have sold to the clearing manager during the quarter, including your own generation, and any generation you sell to the clearing manager on behalf of your customers or other arrangements (such as joint ventures etc where you are selling the electricity to the clearing manager)

"Electricity demand" means the total electricity you have purchased from the clearing manager during the relevant quarter

"Electricity generation" means the total electricity you have sold to the clearing manager during the quarter, including your own generation, and any generation you sell to the clearing manager on behalf of your customers or other arrangements (such as joint ventures etc where you are selling the electricity to the clearing manager)

Appendix A Template disclosure form (typical quarter)

Certificate of Spot Price Risk Disclosure provided pursuant to Subpart 5A of Part 13 of Electricity Industry Participation Code

	Quarter to which disclosure statement applies	Qtr/Year	
1	Name(s) of Disclosing Participant(s)		
	Include names of all Disclosing Participants if a consolidated statement is being submitted pursuant to clause 13.236C of Code		
2	Annual net cash flow from operating activities	$m	
	Based on most recent audited financial statements		
3	Shareholders' equity	$m	
	Based on most recent audited financial statements		
		Stress test results	
		E1	C1
		Energy test	Capacity test
4	Increase/(decrease) in projected net cashflows from operating activities when the stress test is applied*	$m	$m
5	Increase/(decrease) in projected value of electricity sold to the clearing manager when the stress test is applied*	$m	$m
6	Increase/(decrease) in projected of value of electricity purchased from the clearing manager when the stress test is applied*	$m	$m
	** Calculated as the projected value when the respective stress test is applied, minus the projected value when the base case is applied. See paragraphs 2.21 to 2.42 for Energy test and 2.43 to 2.60 for Capacity test.*		
7	Does the disclosing participant listed in question 1 have an explicit risk management policy in respect of its exposure to the wholesale market?	Yes / No	
		Target cover ratio results	
8	If the answer to 7 is Yes, what is the target cover ratio for each stress test*	E1	C1
		Energy test	Capacity test

9	If the answer to 7 is Yes, what is the target cover ratio for each of the 11 quarters beyond the immediate quarter (starting Q2, finishing Q12)?*	Q2 Q3 Q4 Q5 Q6 Q7 Q8 Q9 Q10 Q11 Q12
	* See paragraph 2.61 to 2.77	
10	Did the disclosing participants listed in question 1 submit a Spot Price Risk Disclosure Statement in the previous quarter?	Yes / No
11	What was the actual cover ratio for each stress test for last quarter?	Actual cover ratio result

I____

being a [director/chief executive officer or equivalent/chief financial officer or equivalent]

of____

certify that this Disclosure Statement in all material respects complies with the requirements of clauses 13.236(E) of the Electricity Industry Participation Code.

Signed	
Date	

Appendix B Stress test and base case information

Table 4 Stress test scenarios

	Energy shortage stress tests		Capacity shortage stress test	
Reference code	E1	EB	C1	CB
Nature of event	Sustained national drought (no public conservation campaign)	Base case for energy tests	Unexpected short-term capacity shortage at time of high demand	Base case for capacity tests
Key features of scenario	Average spot prices for the coming quarter are elevated Opening national hydro storage based on prevailing conditions[7] Generation/inflows adjusted by factors[7]	'Average' conditions apply Opening national hydro storage based on average conditions[7] Average hydro inflows prevail[7] Closing national storage equates to average conditions[7]	Spot prices are $21,000/MWh across 8 peak hours of one day Other assumptions described in paragraph 2.56 to 2.58	'Average' conditions apply Other assumptions described in paragraph 2.56 to 2.58
Average level of prices	For 2025: North Island: $400/MWh South Island: $500/MWh For future years: see Table 5 or Participant's own calculated price[8]	For 2025: $100/MWh (time weighted average at Otahuhu) For future years: See Table 5	$21,000/MWh (time weighted average at Otahuhu) or Participant's own calculated price [8]	$100/MWh (time weighted average at Otahuhu)

7 See paragraphs 2.45 to 2.55 for more detail

8 See paragraphs 2.15 to 2.17 for more detail

Table 5: Spot prices for energy stress test for the next 10 years

Year	Energy stress test prices (E1)		Energy base case prices (EB)
	South Island prices ($/MWh)	North Island prices ($/MWh)	South and North Island prices ($/MWh)
2025	500.00	400.00	100.00
2026	510.00	408.00	102.00
2027	520.20	416.16	104.04
2028	530.60	424.48	106.12
2029	541.22	432.97	108.24
2030	552.04	441.63	110.41
2031	563.08	450.46	112.62
2032	574.34	459.47	114.87
2033	585.83	468.66	117.17
2034	597.55	478.04	119.51