ELECTRICITY
AUTHORITY
TE MANA HIKO

9 November 2022

s9(2)(a)

By email: s9(2)(a)

Dear s9(2)(a)

Thank you for your request, received on 19 October 2022, for the following information under the Official Information Act 1982 (the Act):

- “The report the Authority produced for its Board that described staff’s review/analysis of the winter security standards and the merit of updating them.”

The Authority has identified one document within scope of your request: the “Winter Security of Supply Standards” report prepared for the board including the appendices “Draft information paper: Winter Security of Supply Standards”, and “Concept ‘Review of security margins modelling’”. This is attached to this letter.

The winter security of supply standards review showed that some changes to the security of supply standards may be warranted. However, the benefits of amending the standards at the time was limited because the effect of any potential amendments would be minor. To reduce the regulatory burden on stakeholders the Authority did not propose any changes.

Please note that this document was produced in 2018 for internal purposes and the appendices to the report are in draft form only. The Authority makes no representation as to the accuracy of or completeness of the information or views contained in the now outdated draft document.

You have the right to seek an investigation and review by the Ombudsman of this decision. Information about how to make a complaint is available at www.ombudsman.parliament.nz or freephone 0800 802 602.

If you wish to discuss this decision with us, please feel free to contact us by emailing oia@ea.govt.nz.

Yours sincerely

D H Watt

Doug Watt

GM Legal, Monitoring and Compliance (Acting)

Meeting date: 28 June 2018

Winter Security of Supply Standards

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Date prepared: 14 June 2018

Winter Security of Supply Standards

1 Recommendations

1.1 It is recommended the Board:

(a) **note** that staff have completed a review of the *Winter Security of Supply Standards* (the review), attached in Appendix A

(b) **direct** staff to close the project to review the security of supply standards, as listed in the 2017/18 work programme.

2 Rationale

2.1 The target for the 2017/18 work programme was to “Complete a review of the Code mandated security margins and the SSAD”. The review attached in Appendix A satisfies this target.

2.2 The Board can approve recommendation 1.1(b) because:

(a) the recalculated winter energy margin for New Zealand is largely unchanged from the current margin in the Code

(b) while a winter energy margin for the South Island is unnecessary, there is little adverse effects with maintaining it

(c) the winter capacity margin for the North Island is, in effect, largely unchanged from the current margin in the Code. While it has flaws that likely misleads stakeholders, these can largely be overcome with improved communication

(d) removing this project from the 2018/19 work programme is aligned with the Board’s desire to focus on fewer, higher priority projects.

3 Next steps

3.1 Staff will:

(a) inform the system operator that the Authority will not go to consultation for the reasons outlined in 2.2

(b) prepare a Market Brief article which communicates to stakeholders that a review has been completed and the Authority is satisfied with the current standards. If practical, this will be coordinated with any other communication regarding re-prioritisation of the 2018/19 work programme.

4 Background to the security of supply standards

4.1 The winter energy margin (WEM) and winter capacity margin (WCM) security of supply standards are key parts of the framework for monitoring medium-term security of supply.

(a) The WEM security of supply standards are used to assess whether there will be an efficient level of reserve generation and south-flowing transmission capacity to manage extended dry sequences.

(b) The WCM security of supply standard is used to assess whether there will be an efficient level of peaking generation and north-flowing transmission capacity to meet peak demand.

(c) The standards identify the optimal level of energy and capacity, where the cost of adding more supply balances the reduction in shortage costs incurred by consumers. The standards are determined using models that calculate the total costs of reserve generation and the costs of shortage across a range of reserve generation levels.

4.2 The standards were originally established by the Electricity Commission in 2007 (WEM) and 2008 (WCM). The standards were last reviewed in 2012. At that time, it was envisaged that the standards would be reviewed roughly every five years.

4.3 Since 2012 there has been significant change in generation (such as the commissioning of Mill Creek and decommissioning of Otahuhu B and Southdown) and transmission infrastructure (especially HVDC capability).

4.4 There is also more data available, especially in the case of wind generation where the data is vastly more representative than previously.

4.5 In its work programme, the Authority committed to completing a review of the security of supply standards by 30 June 2018 (item 'E1' on the work programme).

5 The current standards are, in effect, not materially different to the findings in the review

5.1 The review reached the following conclusions.

Table 1: Summary of key results

Standard	Existing range	Proposed range from the review	Staff comment
NZ-WEM	14 – 16%	12 – 19%	Results are approximately equivalent
SI-WEM	25.5 – 30%	Remove from the Code as it is unnecessary	Current standard does not add any value, but does not create material costs by maintaining
WCM	630 – 780 MW	~660 – 810 MW (using a like-for-like approach to the existing range)[1]	Results are approximately equivalent

5.2 The analysis and discussion of the review is set out in the information paper attached as Appendix A. That information paper was structured and written as a consultation paper, so can easily be converted back to a consultation paper should the Board reject the recommendation to close the project.

5.3 The Authority's assumptions and modelling have been independently reviewed by Concept Consulting Group. The report is attached as Appendix B to this paper.

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[1] The actual proposed range in the review is 200-450 MW because of proposed presentation changes.

6 There are risks with closing the project early

6.1 The standards are about six years old. As such, failing to update the current standards:

(a) may portray that the Authority has lost interest in promoting security of supply

(b) may create reputational risk given the government policy focus on an orderly transition to a low-carbon future means stakeholders will be increasingly focused on understanding generation.

6.2 The current standards include unnecessary and misleading margins.

(a) The review has shown the SI-WEM is unnecessary. Retaining it will:

(i) force the system operator to continue to expend effort to undertake analysis

(ii) mean some readers will continue to mistakenly draw meaning from it.

(b) The review has found that the WCM is misleading. Retaining it in its current form means that:

(i) some readers of the system operator's annual assessments will still misinterpret the results

(ii) if there are changes to the amount of reserves actually procured by the system operator, or changes to the proportion of those reserves provided by interruptible load, the system operator's annual assessments will be unable to adjust as those factors are 'baked in' to the current standards.

6.3 As the project is 65 per cent complete (by timeframe, and more than that by effort) and on track for delivery in November 2018, closing the project now forgoes an opportunity for the Authority to be seen as completing work it starts.

6.4 Staff planned a more fulsome examination of the standards framework in the next few years. Closing the project now may:

(a) accelerate the need for the future review of the standards framework, by retaining standards that cannot adjust for actual uptake of distributed generation and actual performance of grid-scale wind generation

(b) compromise that future review by not seeking submissions on the future of the standards framework.

7 Attachments

7.1 The following item is attached to this paper:

(a) Draft information paper "Winter Security of Supply Standards"
(b) Concept "Review of security margins modelling"

Appendix A Draft information paper “Winter Security of Supply Standards”

Winter Security of Supply Standards

Information paper

Executive summary

Note for the Board

Staff had originally prepared a consultation paper as it was expected that the project to review the security of supply standards would be part of the 2018/19 work programme.

For the reasons set out in the accompanying Board paper, staff now recommend not proceeding to consultation. However, due to the timing of decisions about the draft work programme it was not possible to make the required changes to this paper.

Key findings have been highlighted in yellow to assist reconciling potentially conflicting information between this paper and the Board paper.

The winter energy margin (WEM) and winter capacity margin (WCM) security of supply standards are key parts of the monitoring framework for medium-term security of supply.

These standards serve as points of reference for industry stakeholders when assessing how likely it is that there will be efficient levels of generation available to meet demand in the next 1-10 years.

The WEM security of supply standards are used in the process of assessing whether there will be an efficient level of generation to manage extended periods of low inflows to hydro generators.

The WCM security of supply standard is used in the process of assessing whether there will be an efficient level of generation to meet peak demand.

The Authority has reviewed the standards, which were last reviewed in 2012, and seeks feedback on proposed changes.

The Authority proposes to replace the national energy security of supply standard of 14-16% with a range of 12-19%, where:

- NZ-WEM below the lower standard of 12% would indicate an inefficiently low level of investment (where the cost of adding more supply would be more than justified by the reduction in shortage costs during extended periods of low inflows)
- NZ-WEM between 12% and 19% would indicate an efficient level of investment (subject to key uncertainties in determining the optimal point)
- NZ-WEM above the upper standard of 19% would indicate a level of investment that was inefficiently high in terms of the trade-off between supply costs and the cost of shortage in extended dry sequences (but might still be efficient for other reasons).

This proposed change reflects up-to-date assumptions and the application of a new calculation model. A notable change to the assumptions is the inclusion of contingent hydro storage that is only accessible in security of supply events.

The Authority also proposes to remove the South Island energy security of supply standard, as it is no longer useful. The standard was established in 2007 at a time where there was limited transfer capacity on the inter-island HVDC link. The upgrade of that link means that there is unlikely to be a situation where South Island energy supply is constrained while the NZ-wide energy supply is not.

In tandem with the above proposed changes, the Authority also proposes to replace the capacity security of supply standard of 630-780 MW with a range of 200-450 MW, where:

- WCM below the lower standard of 200 MW would indicate an inefficiently low level of investment (where the cost of adding more supply would be more than justified by the reduction in shortage costs at times of insufficient capacity)
- WCM between 200 and 450 MW would indicate an efficient level of investment (subject to key uncertainties in determining the optimal point)
- WCM above the upper standard of 450 MW would indicate a level of investment that was inefficiently high in terms of the trade-off between supply costs and the cost of shortage at times of insufficient capacity (but might still be efficient for other reasons).

This proposed change reflects a methodology decision to separately account for the reserve requirement, rather than including it in the WCM itself. Doing this gives the system operator the discretion to consider what reserves are actually being procured and the share that will be met from interruptible load (IL). IL is delivered from the demand-side and does not require additional, generation capacity to be made available.

The Authority is also considering how to make sure the security of supply framework—that includes these standards—remains robust into the future. In particular, technology changes are likely to influence the value that consumers place on grid-supplied electricity and the costs of providing energy and capacity in the future.

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1 A review of the security of supply standards is timely

1.1 The capacity and energy standards, and the corresponding winter capacity and energy margins, are key parts of the policy framework for the monitoring of security of supply. The standards provide a reference measure of the surplus capacity and energy required to provide an efficient security level.

1.2 The efficient security level is a theoretical calculation of the level of generation above expected demand required to minimise the combined cost of shortage and the cost to maintain and operate the additional generation. In other words, the point where the marginal cost of adding new generation is equal to the marginal benefit of reducing unserved demand for electricity.

1.3 The margins are the actual levels for comparison against these standards. The system operator is required to calculate and publish the forecast margins for at least the coming five-year period as part of its annual security of supply assessment.

1.4 The standards are specified in Part 7 of the Code, while the method used to calculate the margins is set out in the system operator's Security of Supply Forecasting and Information Policy (SOSFIP). The SOSFIP is a document incorporated by reference into the Code. Part 7 also requires the system operator to apply any assumptions published by the Authority when undertaking the annual security of supply assessment.

The standards are used to monitor energy and capacity security

1.5 Under the existing electricity market arrangements there is no central party responsible for ensuring that consumer electricity demand can be satisfied.

1.6 Regulatory and market arrangements place a range of incentives on participants to ensure that appropriate levels of supply security are achieved. Examples of these include:

(a) wholesale (or 'spot') market pricing processes and derivative markets, where prices rise as supply becomes scarce

(b) the customer compensation scheme, where retailers are required to compensate consumers for reducing demand during official conservation campaigns.

1.7 Transparent information about actual and forecast levels of supply security assists participants with making operating and investment decisions.

1.8 Looking 1-10 years ahead, the relevant measures are the capacity and energy standards, and the corresponding calculation of the actual winter capacity and energy margins.

Table 1: The standards and how they are applied

	Winter Capacity	Winter Energy
Description	Ability of the power system to supply peak demand	Availability of sufficient 'fuel' to supply demand over the winter period

	Winter Capacity	Winter Energy
Standard	Reference measure – represented as the margin by which generation exceeds expected demand that optimally trades-off the cost of additional supply against the cost of unmet demand. The standards are defined in clause 7.3 of the Code.	
Actual margin	Actual measure – current and forecast levels for comparison with the standards. The actual margins are calculated by the system operator and published in its annual assessments of security of supply.	

Source: Electricity Authority

The nature of supply and demand is becoming increasingly dynamic

1.9 Recent years have seen significant changes in New Zealand's electricity generation fleet and transmission infrastructure, and the emergence of a range of technologies that facilitate an increased role for consumers in the operation of the market.

1.10 The retirement of a range of thermal generation assets has affected both the available capacity and the capability of the system to meet winter energy demand. The government is also now commencing investigations into how to achieve a target of 100% electricity supply from renewable sources in a normal hydrological year by 2035, signalling that further change in the asset fleet are likely to occur.

1.11 At the same time, a wide range of new consumer technologies have emerged that we expect will impact both capacity and energy. For example, solar photovoltaic (PV) and battery technology could impact energy and capacity respectively.

1.12 In particular, the widespread adoption of batteries could fundamentally change the value consumers place on unserved energy from the 'grid' over time periods of up to a few hours, and the corresponding calculation of the capacity margin.

The standards must remain robust to this dynamic environment

1.13 It has been nearly six years since the standards and the associated methodology were last reviewed. While the current capacity and energy margins are expected to exceed the standards for the next few years,[1] it is timely that we review the standards, methodology, and assumptions, to ensure they remain robust for the current market environment. We are taking the opportunity presented by this review to also seek submissions on whether the standards are a suitable approach in the future.

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[1] The current margins are set-out in the system operator's 2018 Annual Security Assessment, available at https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment.

2 The Code requires the system operator to use the security of supply standards

The standards are used for medium-term security forecasting

2.1 One of the functions of the system operator is to provide information and short to medium-term forecasting on all aspects of security of supply.[2]

2.2 The key elements of this forecasting are the capacity and energy security of supply standards, the:

(a) New Zealand winter energy margin (NZ-WEM)

(b) South Island winter energy margin (SI-WEM)

(c) North Island winter capacity margin (WCM).

2.3 The use of winter measures reflects that New Zealand's electricity demand is at its greatest over this period. An optimal margin over winter represents the optimal outcome overall. The Code effectively defines 'winter' as:

(a) 1 April to 30 September for the purposes of any winter energy margin

(b) 1 April to 31 October (7 am to 10 pm) for the purposes of any winter capacity margin.

2.4 The use of only a North Island capacity margin reflects that it has higher peak demand relative to the available generation. An optimal margin for the North Island represents the optimal outcome for the NZ power system overall.

2.5 As outlined in 2.7, the standards serve as points of reference in assessing how likely it is that economically efficient levels of generation will be available to supply demand in the next 1-10 years.

2.6 The capacity security of supply standard is used to assess whether there will be an efficient level of generation given the available north-flowing transmission capacity to meet peak demand.

2.7 The energy security of supply standards are used to assess whether there will be an efficient level of generation capability given the variability of inflows into hydro catchments

2.8 The references to "efficient levels" reflect that there is a theoretically optimal level of investment where the combined cost of shortage and generation is minimised. In other words, the level where the marginal cost of adding new generation is equal to the marginal benefit of reducing unserved energy. In practice, any investment may consider both energy and capacity in tandem, and security of supply will not be the only driver for investment or retirement. When all other factors are considered a different margin may be optimal. Despite this, the standards should be useful to stakeholders as a common reference for assessing the medium-term supply and demand balance.

2.9 The security of supply standards and margins assess physical capacity, and this may be different from the capacity that the market will deliver in any given trading period. The

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[2] Clause 7.3 of the Code.

system operator uses other monitoring tools with a short-term or real-time horizon for this purpose.

The standards are specified in the Code

2.10 The standards were originally developed by the Electricity Commission (Commission). The energy standards were first set in 2007, as an outcome of the Commission engaging Castalia Strategic Advisors to review security of supply policy arrangements.[3] The capacity standard followed in 2008. The standards were key aspects of the Commission's Security of Supply Policy.[4] This policy set out that, under the Reserve Energy scheme, the Commission would consider contracting for additional reserve capacity or reserve energy if either the WCM or WEM measure was expected to fall below the relevant standard.

2.11 When the Reserve Energy scheme was terminated in October 2010[5] the standards were no longer linked to procurement of reserve energy or capacity. They instead became part of the security of supply monitoring framework, and are now intended to provide market participants and other stakeholders with information about future security of supply risks and investment opportunities.

2.12 In 2012 the Authority reviewed the standards to ensure they reflected changes such as the pending availability of new Pole 3 of the HVDC link and changes to the generation mix.[6] As a result of this review, the Authority amended the Code to include revised standards.[7] These new standards provided a range for each of the margins, as opposed to single number, to reflect the uncertainty in the calculated outcomes. The system operator was also requested to undertake a review of the SOSFIP to align the methodology for calculating the margins with the methodology used to develop the standards.

2.13 The current security of supply standards, resulting from the 2012 review, are defined in clause 7.3(2) of the Code as follows:

(a) NZ-WEM: 14-16%

(b) SI-WEM: 25.5-30%

(c) WCM: 630 – 780 MW.

2.14 However, the levels of expected demand that these standards are referenced above are not clearly defined.

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[3] http://www.castalia-advisors.com/files/22631.pdf

[4] https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/security-of-supply/security-of-supply-policies-archive/

[5] The Reserve Energy scheme was terminated as part of the dissolution of the Electricity Commission under the Electricity Industry Act 2010, with the intention that reserve generation should instead be supplied through market mechanisms.

[6] Information on the 2012 review is available at: https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/work-programmes/market-wholesale-and-retail-work/security-of-supply-standards/. The base case modelling did not include an increase in inter-island transfer capacity on the HVDC link, despite the new Pole 3, as there were other constraints in the AC system. Those AC constraints have since been removed.

[7] The Electricity Industry Participation (Supply Standards) Code Amendment 2012, available at https://www.ea.govt.nz/code-and-compliance/the-code/amendments/2012-code-amendments/

The standards are applied in the system operator's monitoring and forecasting

2.15 As noted in 3.1, security of supply monitoring and forecasting is now the responsibility of the system operator. Part 7 of the Code specifies that the system operator shall prepare, publish, implement, and comply with the SOSFIP. The SOSFIP must include a requirement that the system operator prepare and publish at least annually a security of supply assessment (ASA).[8]

2.16 The ASA must contain detailed supply and demand forecasts for at least the next 5 years and enable interested parties to assess whether the capacity and energy security of supply standards are likely to be met.[9] The methods used to calculate the margins in the ASA are set out in the SOSFIP.[10]

2.17 The Authority wants to ensure the actual margins calculated by the system operator provide a meaningful comparison with the standards. For that reason, the Code also requires the system operator's ASA to use a set of assumptions published by the Authority (where the Authority has elected to do so), unless the system operator considers there are good reasons to use different assumptions and sets out its rationale for doing so.[11] The assumptions can (and do) include aspects of the calculation methodology, and are not just model inputs.

2.18 The SOSFIP, 2018 ASA[12] and the Authority's current security of supply assumptions document (SSAD)[13] are all publicly available.

The standards need to reflect the actual market environment

2.19 The security of supply standards are intended to be robust over time. They will shift as aspects of the power system change (including generation mix, transmission configuration, fuel costs, shortage costs, etc).

2.20 When the standards were established it was envisaged that they would be reviewed roughly every five years. It is the Authority's role to review the standards because they are set out in the Code.

2.21 The Authority has reviewed the security of supply standards and seeks feedback on proposed changes to the standards. These proposed changes are set out in sections 4-5 of this consultation paper.

2.22 The standards and calculated margins are dependent on the calculation methodology and input assumptions. The use of a recognised methodology provides for the calculations and outcomes to be consistent over time, enabling participants to consider how changes in the market may be affecting security of supply. To achieve this consistency, the methodology must be robust to changes in the nature of supply and demand.

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[8] Clause 7.3(1)(a) of the Code.

[9] Clause 7.3(1)(a)(i) of the Code.

[10] The current SOSFIP is available at https://www.transpower.co.nz/system-operator/security-supply/security-supply-forecasting-and-information-policy or http://www.ea.govt.nz/act-code-regs/code-regs/the-code/part-7/.

[11] Clauses 7.3(2A) to (2D) of the Code.

[12] https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment

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

2.23 The input assumptions can also have a material impact on the calculations, and may change relatively frequently as participants change their operational and investment activities in response to market conditions (for example, through making enhancements to existing assets to drive increased performance and efficiency). The calculation of the margins in the ASA needs to reflect the best available assessment of these assumptions for the outcomes to be meaningful.

2.24 This consultation paper sets out the methodologies and assumptions applied in the calculation of the revised standards, and seeks feedback on both. The methodologies and assumptions are set out in sections 4 and 5 for energy and capacity standards respectively. The proposed revised version of the Authority's SSAD is also provided in Appendix C for feedback.

3 We have recalculated the energy security of supply standards

The calculation applies the same methodology as the 2012 review, but uses a new model

3.1 The process used to calculate the standards remains essentially the same as that used by the Commission when they established the standards in 2007. In brief, the process used is to:

(a) develop and run a model to estimate the optimum amount of generation capacity required

(b) consider various sensitivities

(c) having regard to the modelling form a decision as to the appropriate standards.

3.2 The analysis seeks to find the WEM that minimises the expected sum of generation costs and energy shortage costs across different inflow sequences. The expected costs are estimated using a market simulation model. The model only considers energy shortage costs that arise from periods of high spot prices, public conservation campaigns and rolling outages—it does not consider the costs of shortage during capacity shortfalls.[14]

3.3 The modelling process uses a base case that represents the current system which has some generation removed to invoke shortage, and the additional generation progressively added to it until the optimum point is identified. A detailed description of the process, methodology and assumptions is provided in the document "Winter Energy and Capacity Security of Supply Standard modelling assumptions" that is provided as a companion paper (modelling assumptions companion paper) to this consultation paper.

3.4 A similar methodology to that used for the NZ-WEM is applied to calculate the optimal SI-WEM, except that demand is increased to invoke shortage rather than removing generation.

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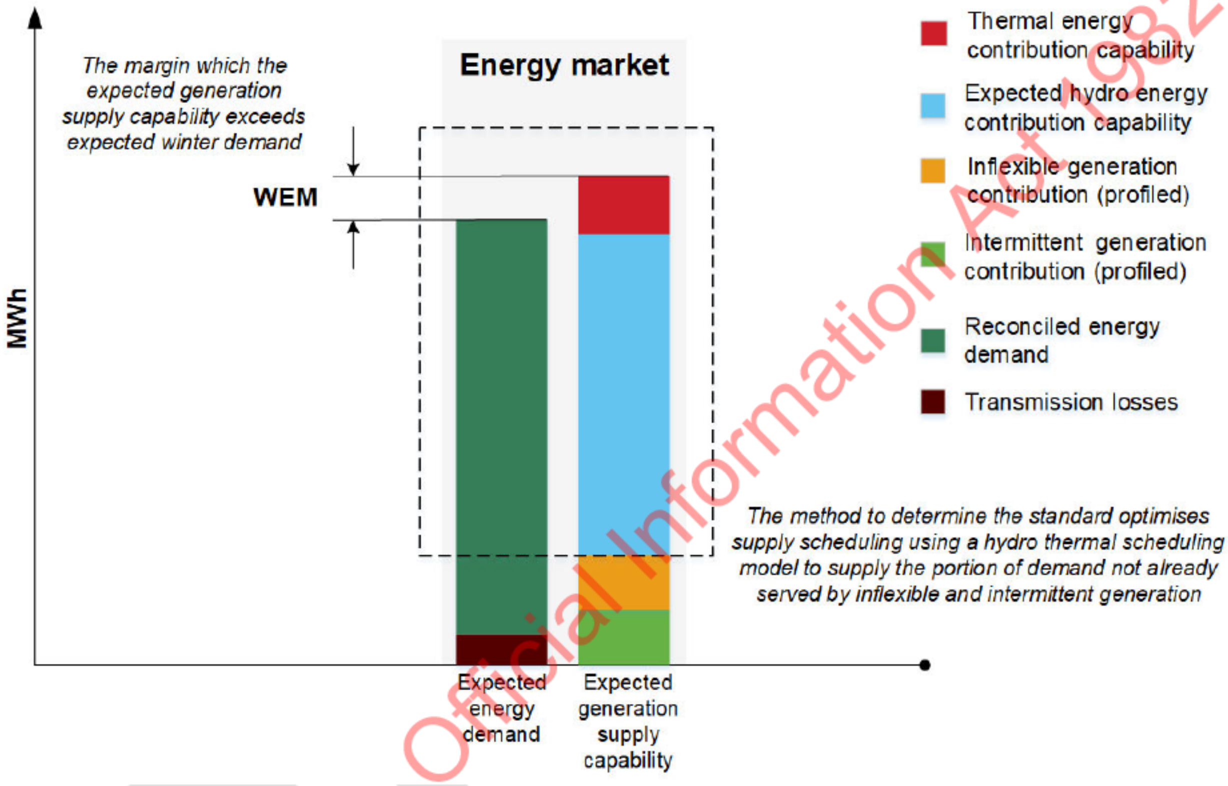
[14] In principle, it would be possible to determine a combination of WCM, NZ-WEM and SI-WEM that jointly minimised the total costs of energy and capacity shortages, but this is not the approach followed here. Co-optimising a solution would be seeking to calculate the outcome to a level of accuracy that does not reflect the broad assumptions made in the inputs. Deriving each margin on the basis that it is the binding condition enables a more considered discussion on the respective risks and uncertainties in the supply of energy and capacity.

3.5 The WEM represents the margin by which expected energy supply capability exceeds expected demand in winter. The expected energy supply capability considers thermal to be fully fuelled and that hydro fuel (winter inflows and storage) can be consumed to supply winter energy demand. Figure 1 illustrates the WEM.

Figure 1: The WEM in relationship to the energy market



Source: Electricity Authority

Notes:
1. Energy contribution capability is the energy able to be suppled from the various generation assets that can be used to supply demand.
2. Expected hydro energy contribution capability refers to the expected energy available from hydro while taking in to account the variation in the distribution of inflows.

3.6 The Authority has used a hydro-thermal scheduling model that explicitly takes account of the uncertain nature of hydro inflows. The portion of Figure 1 within the dashed line highlights that this modelling is only concerned with the optimal scheduling of flexible generation plant to supply demand that is not already served by inflexible and intermittent generation. The particular model used is a New Zealand-specific version of the Dynamic Outer Approximation Sampling Algorithm (DOASA) developed for the NZ electricity system by Stochastic Optimization Ltd.[15] DOASA has been used for years in academic, regulatory and commercial environments. All model inputs are able to be easily and transparently modified thereby enabling a range of experiments to be undertaken.

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[15] See https://www.emi.ea.govt.nz/Content/Tools/Doasa/DOASA%20paper%20by%20SOL.pdf for more information.

3.7 The Authority's assumptions and modelling have been independently reviewed by Concept Consulting Group. The scope of that review has included the Authority's use of DOASA, but not the DOASA model itself.

3.8 The model estimates the societal cost of unserved energy (in NZ$M p.a.) for a given scenario and level of additional generating capacity using the methodology set out in the modelling assumptions companion paper.

3.9 The factors simulated or represented within the modelling framework include:

(a) Demand factors:

  (i) variability in demand

  (ii) system losses

  (iii) demand response to high spot prices, voluntary conservation during public conservation campaigns, mandatory conservation during rolling cuts, and the associated costs with these responses to shortage

(b) Supply factors:

  (i) variation in inflows into hydro reservoirs

  (ii) variation in the starting level of the hydro reservoirs

  (iii) management of flexible generation, including controlled hydro and thermal and associated costs

  (iv) availability factors for thermal plant

  (v) generation from inflexible generation including run-of-river hydro and geothermal (profiled)

  (vi) generation from intermittent generating plant including wind and other embedded generating assets (profiled)

(c) Transmission factors:

  (i) constraints on the power flow between the islands.

3.10 Factors excluded from the modelling include:

(a) fuel constraints

(b) AC transmission constraints

(c) strategic generator behaviour, contracting, and inefficiency.

The modelling uses up-to-date assumptions

3.11 The base case scenario for the NZ-WEM analysis reflects the 2017 electricity market environment. The key assumptions are summarized in Table 2.

3.12 All of the assumptions applied in the analysis are described in more detail in the modelling assumptions companion paper, and the relevant assumptions are also summarised in the draft update of the SSAD provided as Appendix C. Publishing this version of the SSAD would require the system operator to apply these assumptions in the ASA, unless it was able to demonstrate a rationale for doing otherwise.

Table 2: Key assumptions used in the NZ-WEM base case

Issue	Base case assumption
Demand factors	Shortage costs as set out in paragraphs 4.17 to 4.22
Supply factors	Existing generation: • Available contingent hydro storage in Lakes Hawea, Pukaki and Tekapo is modelled as active storage[16] • The start storage for controlled storage at 1 January is the mean of the last 20 years. • 2017 generation fleet available with the following thermal plant removed in order to invoke shortage within the modelling: o Huntly Rankine units (2 x 240 MW) o Stratford gas OCGT (2 x 100 MW) o McKee gas OCGT (100 MW) o Whirinaki diesel OCGT plant (155 MW) • Forced outage rates of 3% (thermal) and 2% (hydro) controlled generation • Inflexible and intermittent generation is profiled based on its 2017 output Energy contribution across winter from these generation types is assumed to be relatively consistent year on year. • Fuel costs[17]: o Gas at $6.25/GJ excluding carbon o Coal at $5.10/GJ excluding carbon o Diesel at $23.00/GJ excluding carbon o Carbon at $15/t carbon.

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[16] Available contingent hydro storage is the hydro storage that operable and consented to be used only when specific conditions are met during a hydro shortage event. The conditions are specific to the asset and form part of their resource consents. Lakes Hawea and Pukaki have, respectively, 67 GWh and 178 GWh of year-round available contingent storage. Lake Tekapo has 220 GWh that changes from active storage to available contingent storage over summer. More information https://www.emi.ea.govt.nz/Environment/Datasets/HydrologicalModellingDataset/1_InfrastructureAndHydroConstraintAttributes

[17] Fuel and carbon costs are from MBIE's 'Interactive electricity generation cost model', available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-lrmc-model.xlsm.

Issue	Base case assumption
	Additional generation capacity: • Approach as set out in paragraphs 4.12-4.16 • Costs for open-cycle gas turbines (OCGT) from the 2016 MBIE EDGS report[18]
Transmission factors	Full HVDC bi-pole available at 900 MW transfer capacity in each direction with 100% availability.[19]

Additional generation is modelled as though it is thermal

3.13 The additional generation that is added to reduce shortage during the modelling is assumed to be an OCGT. In scenarios where the available existing energy supply exceeds the standard this assumption will not affect the calculations but in all other cases these costs are a key driver of the modelled outcome (recognising that the efficient outcome is the sum of additional generation costs and the costs of unserved demand).

3.14 This assumption is consistent with what is being observed in the *current* environment, where natural gas appears to be the most likely fuel choice for large-scale (i.e. 50MW+) generation that provides reliable energy, with various resource consents in place to enable them to be built if required.

3.15 The assumption that additional generation will be thermal may be less appropriate in a potential future where the generation mix is transitioning towards the current government's target of 100% renewable generation in a normal hydrological year by 2035[20], and in light of its recent decisions on the future of natural gas exploration. Nonetheless, this assumption seems sound for the majority of the standard's maximum five-year useful lifespan.

3.16 It is important to note that the modelling is not intended to plan and select the most appropriate source of reserve supply, but rather to provide a guide to the level of supply risk and potential investment requirements. The market arrangements should create pressure that the lowest overall cost technology is applied.

3.17 An experiment where all additional generation is modelled as though it is wind was also performed as an extreme scenario, testing whether the assumption made in the base case was reasonable. This experiment showed materially higher system costs than the base case along with a much lower optimal margin, providing some assurance that modelling additional generation as thermal better estimates an efficient standard.

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[18] The Ministry of Business, Innovation and Employment's (MBIE) 'Electricity Demand and Supply Generation Scenarios 2016' (EDGS), November 2016. Available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/documents-image-library/edgs-2016/generation-cost-assumptions.xlsx.

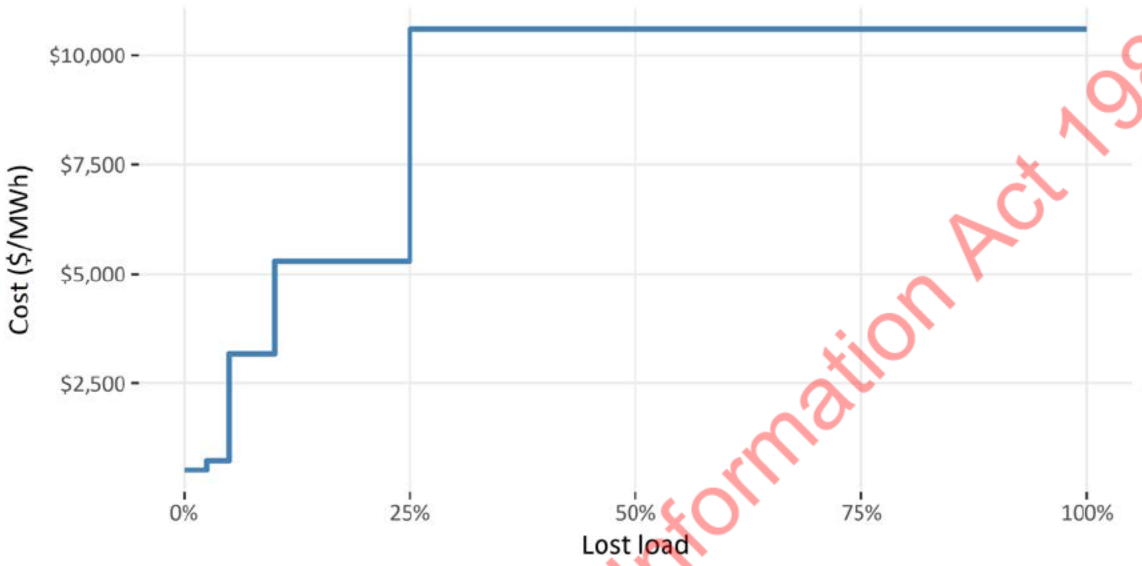
[19] The HVDC is a very reliable asset, but will have small periods of unavailability. However, the effect of such unavailability on energy transfer is negligible as lakes in both islands provide a buffer to store energy for later transfer.

[20] Though there is also a clear inference that non-renewable sources such as natural gas peakers are still expected to be necessary in years with below-average hydro inflows.

Existing assumptions for value-of-lost-load have been applied

3.18 The energy shortage cost assumptions are shown in Figure 1. These use the same values as used in the 2012 review, adjusted for inflation.

Figure 2: Shortage costs: base case and sensitivities



Source: Electricity Authority

3.19 A demand reduction of around 2% has been observed when spot prices rise to around $200/MWh in dry years. Market participants are considered likely to be valuing these demand reductions at around this price.

3.20 In previous dry years, voluntary demand savings of around 5% have been observed during conservation campaigns. It is difficult to know how customers value these demand reductions as they may be motivated by spot price savings (for customers who are exposed to spot at the margin) or by wanting to act in the public interest.

3.21 The base case applies the demand reductions set out in Table 3. Tranches for demand reductions of greater than 5% reflect the implementation of more significant emergency measures (including rolling cuts) if a public conservation campaign fails to alleviate the shortage situation.

Table 3: Demand reduction assumptions used in the NZ-WEM base case

Tranche #	Shortfall (%)	Shortage cost ($/MWh)
1	0 – 2.5%	$530/MWh
2	2.5 -5.0%	$740/MWh
3	5 – 10%	$3,200/MWh
4	10 – 25%	$5,300/MWh

Tranche #	Shortfall (%)	Shortage cost ($/MWh)
5	>25%	$10,600/MWh

Source: Electricity Authority

3.22 Although there has been some investigation into the cost of shortage since 2008, there is no clear evidence to justify further revision of the curve. Transpower is in the process of making new estimates of the value-of-lost-load (VoLL) based on feedback received from industry participants. This revised data was not available while this paper was being prepared.

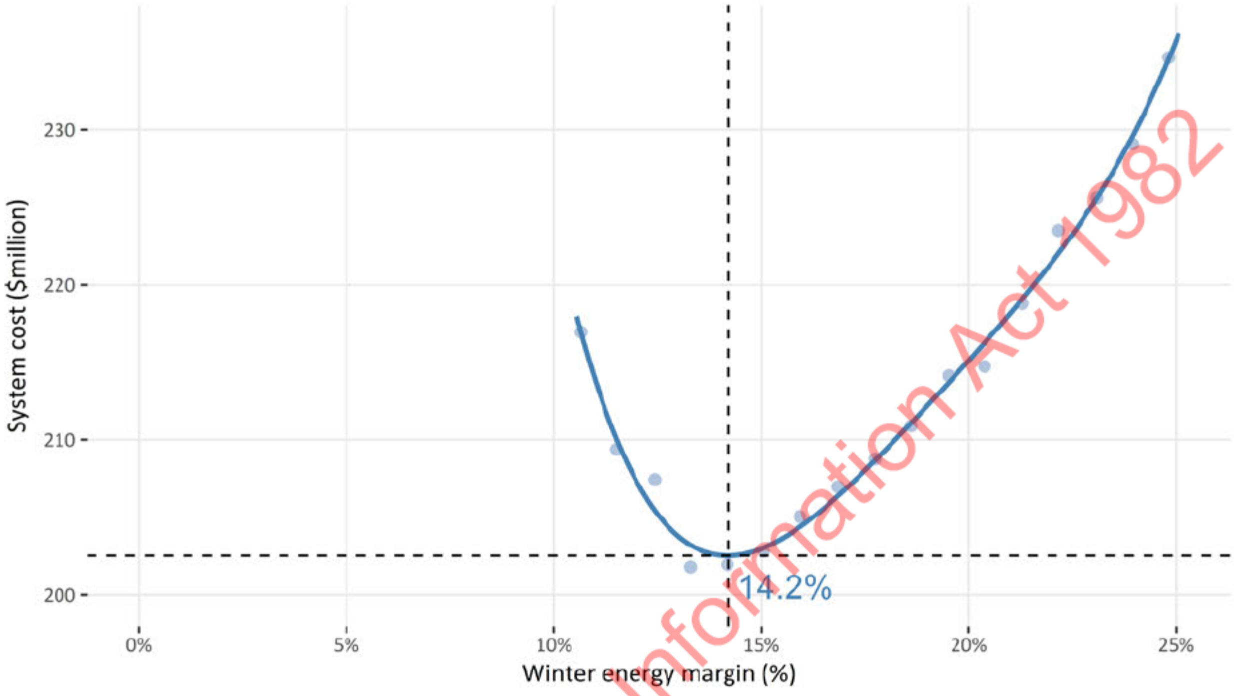
3.23 In the event this new data is made available prior to the Authority's decision on these proposed Code amendments, the Authority intends to consider whether and how to apply that data in setting these standards. In the interim, the modelling has also looked at the sensitivity of the margin to these costs (as described at 4.27-4.30(c)).

Q1. Do you agree with the methodology and set of input assumptions applied in the WEM analysis and proposed to be included in the SSAD? If not, please identify which assumptions you disagree with and provide alternative assumptions, together with a rationale.

The base case shows an optimal NZ-WEM of 14.2%

3.24 The base case results indicate an optimal NZ-WEM threshold of about 14.2%, compared with the current optimum of 14.9% and range of 14-16%. Figure 2 shows the trade-off between the costs of supply and non-supply.

Figure 3: Base case optimal NZ-WEM



Source: Electricity Authority

Notes:
3. The system cost is a reference cost for the modelling runs within a scenario.
4. The system cost is the total of (a) short run marginal cost for generation added to the system when it generates; (b) capital cost of capacity added to the system; and (c) shortage cost of unserved load
5. The model in DOASA only represents part of the demand and supply in the NZ electricity system. It only includes the component of demand not already meet by inflexible and intermittent generation, and on the supply side, the flexible generation that remains to supply this remaining demand.
6. Each light blue dot represents a single result from a 'run' of the model. The amount of additional generation available to the model within the run increases from left to right. Due to the nature of the modelling there is some noise in results.
7. The dark blue line is fitted to the light blue dots.

The proposed and current NZ-WEM are comparable

3.25 The current NZ-WEM has a base case optimum of 14.9%. As such, the proposed 14.2% appears to be a small decrease.

3.26 The treatment of available contingent storage is an explanation of the proposed net reduction in NZ-WEM. The 2018 analysis is sensitive (2.1 percentage points higher) to the removal of contingent storage in Lakes Hawea and Pukaki from the model, as illustrated in Figure 3 and discussed in paragraph 4.32.

(a) In the 2018 modelling:

    (i) All available contingent storage is available to DOASA in the base case. The model is free to use this storage as operating storage. This storage is included as it is available to be used in a significant energy shortage event to avoid or delay incurring the cost of outages.

    (ii) In reality, there is a cost to the use of contingent storage that is not accounted for in the modelling.

(b) In contrast, in the 2012 modelling:

    (i) Available contingent storage was not included. This tends to understate the capability of the power system and result in a higher standard.

3.27 As discussed in paragraphs 2.9-2.12, there have been significant changes to electricity assets and markets since 2012. However, given the proposed small decrease, the net effect of those changes has been minimal on the efficient standard.

The sensitivity of NZ-WEM has been modelled

3.28 To further test the modelled outcome a number of sensitivities have been analysed. These sensitivities test whether the proposed standards are set at the appropriate level, rather than testing whether the proposed standard is sufficient to accommodate the sensitivity scenarios. These scenarios include:

(a) demand sensitivities:

    (i) increased demand (+ 5 per cent)

    (ii) significantly higher and lower shortage (VoLL) costs (± 50 per cent)

(b) supply sensitivities:

    (i) increased and decreased thermal fuel costs (± 20 per cent)

    (ii) with no contingent hydro storage available in lakes Hawea or Pukaki[21]

    (iii) storage levels at the start of the calendar year the same as those seen in the 2006 and 2008 dry years, and at the relatively high level seen in 2011

(c) transmission sensitivities:

    (i) reduced (800 MW) and increased (1,000 MW) inter-island transfer capacity.

3.29 The effects of various sensitivity cases on the optimal NZ-WEM are shown in Figure 3.

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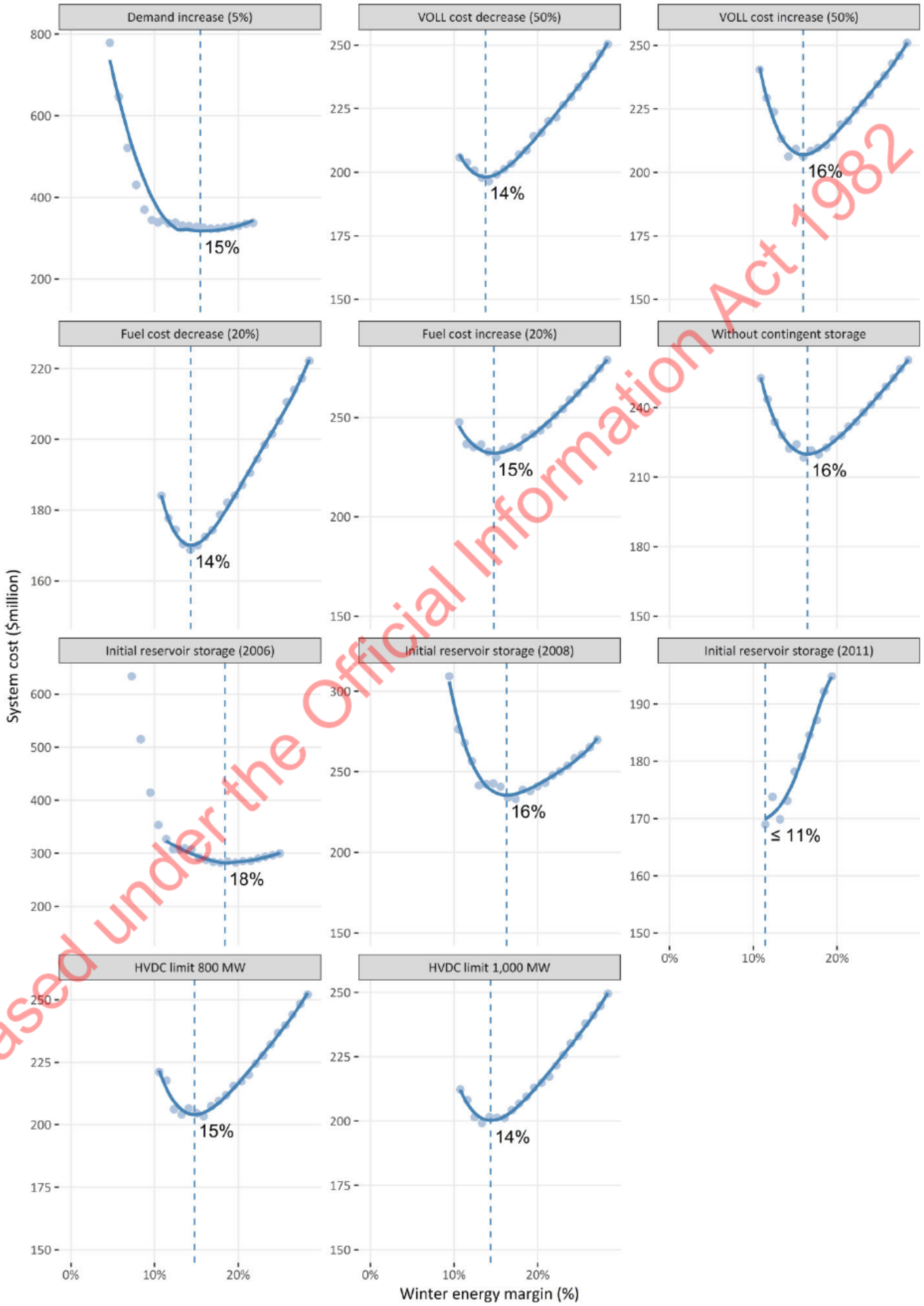
[21] A tranche of Lake Tekapo is ordinary hydro storage from 1 April to 30 September and contingent hydro storage from 1 October to 31 March. As this storage is available during the crucial period of the analysis, it was appropriate to keep it available to DOASA in this sensitivity.

Figure 4: Optimal NZ-WEM under various sensitivities



Source: Electricity Authority

Notes: 1. All optimums have been rounded to the nearest whole per cent.

3.30 The analysis showed that the optimal NZ-WEM is reasonably insensitive to most of these uncertainties.

3.31 All three scenarios involving the initial hydro storage level show some sensitivity, though none points to a better assumption to use.

- (a) The Authority used the average of hydro storage on 1 January of the last 20 years in its base case. The use of start storage at 1 January allows the model to optimally conserve or use water in the lead-up to winter consistent with the other generation fleet in the system. The scenario for the optimal margin in the base case starts winter (1 April) with 2890 GWh in the South Island or 3350 GWh across New Zealand.
- (b) The 2006 initial 1 January storage level scenarios (low start storage) showed materially higher total societal costs than the base case, but did not result in margins outside the optimal range identified in the base case (i.e. they fell within the range of 12-19%).
- (c) Changes in the electricity market since 2008 appear to have influenced hydro storage management. It seems likely that, under current market arrangements, hydro storage at the start of the winter period would be managed to higher levels than may have been seen in the past. The margin methodology also implicitly recognises that low inflow sequences (which could be one reason for low initial storage) can and do occur. Setting a standard that effectively tries to prevent them from occurring would be inconsistent with that methodology.

3.32 The demand increase scenario showed materially higher total societal costs than the base case, but did not result in margins outside the optimal range identified in the base case. Electricity demand has been relatively flat for several years, with 2017 total consumption essentially the same as that in 2006.[22] There is no evidence to suggest that demand growth will reach 5% in the next few years. The system operator's reporting in the ASA will show whether margins are tightening due to actual and forecast growth. The Authority could decide whether a review of the margins is required at that time.

3.33 The scenario with available contingent hydro storage removed[23] shows about two percentage points of sensitivity and provides useful information.

- (a) The base case assumes that contingent hydro storage is available to DOASA to use as regular storage, though this doesn't reflect the reluctance that hydro generators have to frequently using those resources.

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[22] http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/publications/energy-in-new-zealand/#data.

[23] Available contingent hydro storage is removed from the DOASA model. When interpreting the resulting WEM an adjustment is made to account for the energy stored in contingent storage to ensure we represent an 'apples with apples' comparison to the base case.

(b) This suggests that the most realistic result lies somewhere between the 14.2% optimum in the base case and the 16.3% optimum in the sensitivity with available contingent hydro storage removed.

(c) The Authority has commissioned improvements to DOASA and expects the final calculation of NZ-WEM to be based on modelling that applies a penalty cost for DOASA drawing down contingent hydro storage. This should better represent the hydro generators' reluctance to frequently use contingent hydro storage without having to resort to the extreme of removing contingent hydro storage entirely.

Modelling was unable to produce a meaningful result for SI-WEM

3.34 The SI-WEM is designed to cover the situation where the NZ-WEM may be above the standard, but a potential energy security issue remains in the South Island. This might occur if the ability to utilise North Island generation to send energy south during a South Island supply shortage is significantly limited by transmission constraints between the islands.

3.35 A key assumption in previous calculations of SI-WEM was the assumed north-to-south HVDC transfer during dry years.

(a) In both the original establishment of the standard in 2007, and in the 2012 review, north-to-south transfer was limited (by the HVDC link capability and an AC-transmission constraint, respectively). The transfer capacity was modelled at a maximum of 580 MW and with a lower sustainable average, reflecting that it is not possible to operate a full capacity continuously.

(b) Following the upgrade of the HVDC link, the commissioning of the new Pole 3, and other AC-system upgrades, southward transfer capacity is now significantly higher.

(c) The HVDC has been modelled in this review with a sustainable capacity of 900 MW in both directions (as opposed to 850 MW South, 1200 MW North). This is higher than the actual southward maximum capacity of 850 MW under ideal conditions.[24]

(d) The Authority has commissioned improvements to DOASA to allow different northward and southward limits. After reviewing submissions, the Authority will likely reduce this southward flow assumption to no more than 850 MW. It may be reduced to a capacity of less than 850 MW, depending on advice from submitters (especially Transpower) about the HVDC's limitations under different conditions.

3.36 However, our modelling shows that (regardless of HVDC assumptions) a situation where the NZ-WEM is above the standard and the South Island is experiencing a shortage is difficult to conceive. This is highlighted by the results in Figure 4. The modelled results are for the existing generating fleet, including the thermal plant in the North Island. Demand needs to be increased by nearly 50% before the model starts to invoke the cost of shortage. We then add diesel reciprocating plant in increments of 50 MW to address any shortage and derive an optimal standard.

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[24] To test the impact of using 900 MW instead of 850 MW, we identified occasions when the modelling simulations resulted in southward HVDC transfers greater than 850 MW. 11% of simulations included such transfers. Of those 11% of simulations, the maximum aggregate duration of those transfers was 2% of the hours simulated.

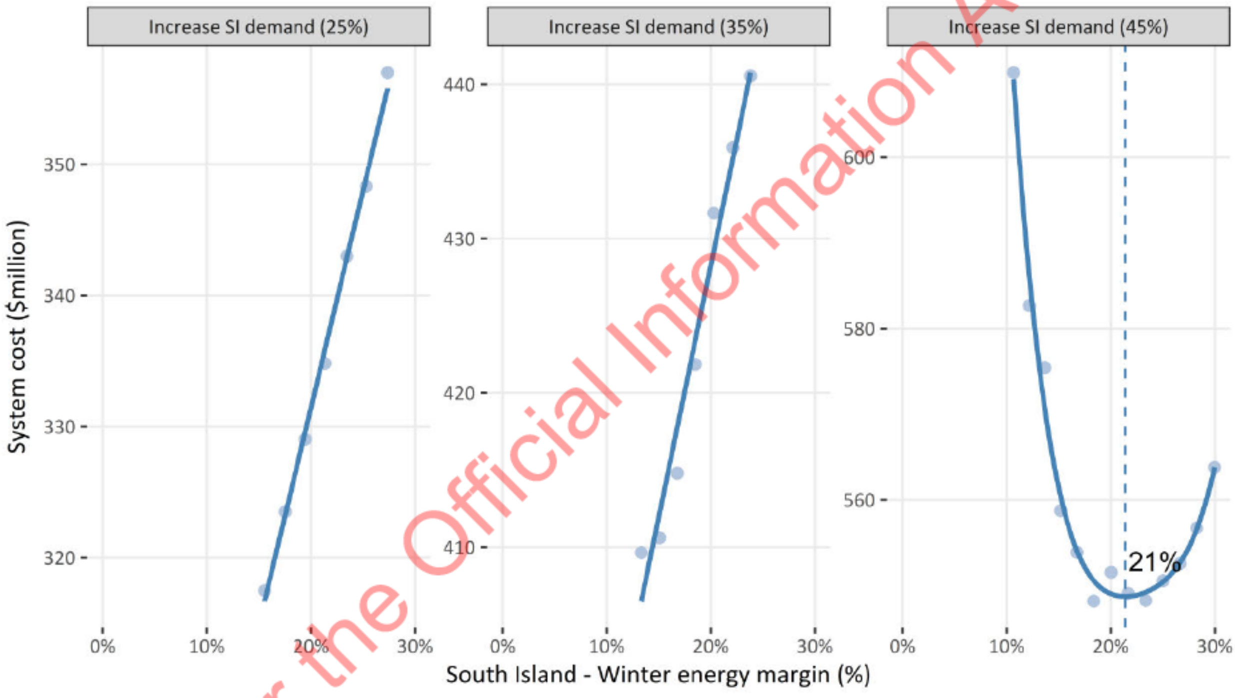
3.37 Figure 4 shows results for three scenarios, each with increasing levels of South Island demand above 2017 levels:

(a) At a 25 per cent demand increase adding thermal increases capital cost to the system but doesn't avoid any shortage cost as demand was already served.

(b) At a 35 per cent demand increase the system cost is higher as more demand is being suppled, but adding thermal still just adds capital cost as there is no shortage cost to avoid.

(c) At a 45 per cent demand increase we eventually start to see shortage that can be avoided by addition of South Island thermal.

Figure 5: Optimal SI-WEM with increased South Island demand



Source: Electricity Authority

3.38 It is possible to derive a South Island energy margin when there is a 45 per cent demand increase, but it makes little sense to do so given:

(a) the demand increase will have already reduced the actual NZ-WEM margin in comparison to the standard

(b) it is completely unrealistic for the scenario to transpire within the maximum useful life of this review of the standards (at most, five years).

3.39 Given these findings the Authority proposes to instead remove SI-WEM from the Code and the SSAD.

The Authority is proposing to change the NZ-WEM and remove the SI-WEM

3.40 Based on the above analysis (including sensitivities), the Authority proposes to:

(a) change the New Zealand energy security of supply standard from a range of 14-16% to a range of 12-19%

(b) remove the South Island energy security of supply standard.

3.41 The proposed Code amendments are set out in Appendix A of this paper.

3.42 The base case analysis suggests that the optimal NZ-WEM is likely to be about 14.2%. This base case assumes optimal energy management that minimises the total societal cost. While attaining this optimal outcome is unlikely to be achievable in practice, the existing market and regulatory arrangements create strong incentives on industry participants to ensure that a relatively efficient level of security is still achieved.

3.43 As with the 2012 analysis, the Authority prefers to acknowledge the uncertainty in deriving an optimal WEM by representing it as a range. A “bright-line” standard may also fail to convey that there is a continuum of investment efficiency, instead suggesting a sudden transition from adequate to inadequate.

3.44 When choosing a range, the Authority has been guided by:

(a) the methods and associated ranges set out in Table 4 below, to connect the range to the modelled costs

(b) rounding results to whole or half per cents, so as to help users not infer more precision than actually exists

(c) the most credible results from the sensitivity analysis, such as the exclusion of contingent hydro storage as described in paragraph 4.27(b)(ii).

3.45 Table 4 below sets out the methods that the Authority has found useful when selecting a range for NZ-WEM. The Authority is likely to use its discretion, guided by these methods, when choosing a final range to be included in the Code. The Authority expects there are likely to be changes in the final range chosen because:

(a) submitters will identify improvements to the overall calculation methodology and/or the input assumptions, such as the results of Transpower’s VoLL study becoming available

(b) the Authority has commissioned improvements to the DOASA software.

Table 4: Guiding methods for selecting and rounding a range for NZ-WEM

Methods	Associated range	Rounding to the nearest half a per cent
$5M above the base case optimum cost	12%-17.3%	12%-17.5%
$10M above the base case optimum cost	11.2%-19.1%	11%-19%
2.5% above the base case optimum cost	12%-17.3%	12%-17.5%
5% above the base case optimum cost	11.2%-19.1%	11%-19%

Source: Electricity Authority

Notes:
1. The base case optimum system cost is $202.4 million. This is the total of (a) short run marginal cost for generation; (b) capital cost of additional capacity; and (c) shortage cost of unserved load.
2. All system costs have been drawn from the line of best fit from the base case (not from any

individual result from the modelling).

3.46 The proposed range for NZ-WEM is from 12% to 19%, where:

(a) NZ-WEM below the lower standard of 12% would indicate an inefficiently low level of investment (where the cost of adding more supply would be more than justified by the reduction in expected shortage costs

(b) NZ-WEM between 12% and 19% would indicate a roughly efficient level of investment (subject to key uncertainties in determining the optimal point)

(c) NZ-WEM above the upper standard of 19% would indicate a level of investment that was higher than efficient in terms of the trade-off between supply costs and the cost of expected shortage (but might still be efficient for other reasons).

3.47 The results in 4.33-4.38 indicate that the South Island energy standard does not provide value as a security metric. There do not appear to be any conditions where the South Island would be experiencing a shortage while the NZ-WEM standard is being achieved.

3.48 The Authority therefore proposes to remove the SI-WEM standard from the Code.

3.49 When considering the proposal to change the NZ-WEM standard it is useful to reflect on the current security of supply situation. The 2018 ASA, calculated using the existing methodology, suggests that NZ-WEM is likely to remain above or within the standard until 2025 (if all existing generation remains) or 2022 (if 500 MW of thermal generation is retired before 2023).[25] The proposed changes to the methodology and standard are not expected to change this outcome.

3.50 As part of this review process the Authority also proposes to publish an updated SSAD, to reflect the revised modelling approach, methodology and assumptions applied in this review of the WCM standard. The draft SSAD is provided at Appendix C. Publishing the updated SSAD would require the system operator to apply a methodology and assumptions that is consistent with that used to develop the standard when forecasting the margins and completing the ASA.

3.51 The Authority is engaging with the system operator about whether the change in the model used for calculating the WEM will have implications for their monitoring activities, including the ASA. Consequential changes may also be required to the SOSFIP. If so, those changes will be pursued through the process set out in the Code.

Q2. Do you agree that the NZ-WEM security of supply standard should be revised to 12%-19%? If not, why not?

Q3. Do you agree that the SI-WEM security of supply standard should be removed? If not, why not and how do you suggest a useful measure might it be determined?

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[25] See footnote 12 for reference.

4 We have recalculated the capacity security of supply standard

The calculation methodology has been revised and improved

4.1 As noted in 3.10, the WCM standard was originally put in place by the Commission in 2008. The Authority's approach for setting the standard is essentially the same as that applied by the Commission. In brief, the process is to:

(a) develop and run a model to calculate the optimum amount of capacity[26]

(b) consider various sensitivities

(c) having regard to the modelling, determine the appropriate standard.

4.2 The analysis described here seeks to find the optimal WCM – the level of generation capacity that minimises the expected sum of shortage costs at times of peak demand and the cost of adding additional generation capacity.

4.3 It may be that a higher WCM is optimal when other considerations are taken into account – for instance, when the ability of generation to also contribute during periods of sustained low inflows is factored in. For simplicity and ease of understanding, no attempt has been made to incorporate these considerations into the modelling.

4.4 The model follows the following steps:

(a) simulating power system operation for each of the top 500 trading periods in a calendar year with the highest demand

(b) determining in each trading period the extent (in MW) of North Island capacity shortage (if any)

(c) applying a shortage cost curve and the costs of any necessary additional generation to determine the societal cost

(d) summing the additional generation costs and shortage costs to provide a total across the 500 trading periods.

4.5 The analysis is then repeated with a different level of additional capacity. The assumed costs of additional generation are outlined in 5.29-5.32 below and are a mix of fixed ($/kW p.a.) and variable costs ($/MWh).

4.6 The process uses a "steady state" analysis (as opposed to a model of the expansion of the generation system over a period of years), with shortage and generation costs expressed in millions of dollars (NZ$M) per annum (p.a.).

4.7 The Authority's assumptions and modelling have been independently reviewed by Concept Consulting Group.

4.8 A more detailed description of the process is provided in the modelling assumptions companion paper.

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[26] The 2008 work used two models, a "convolution" model and a "chronological" model. The latter model was used to calibrate the convolution model. There is no need to repeat this exercise as the insights gained from it are now built into the main model.

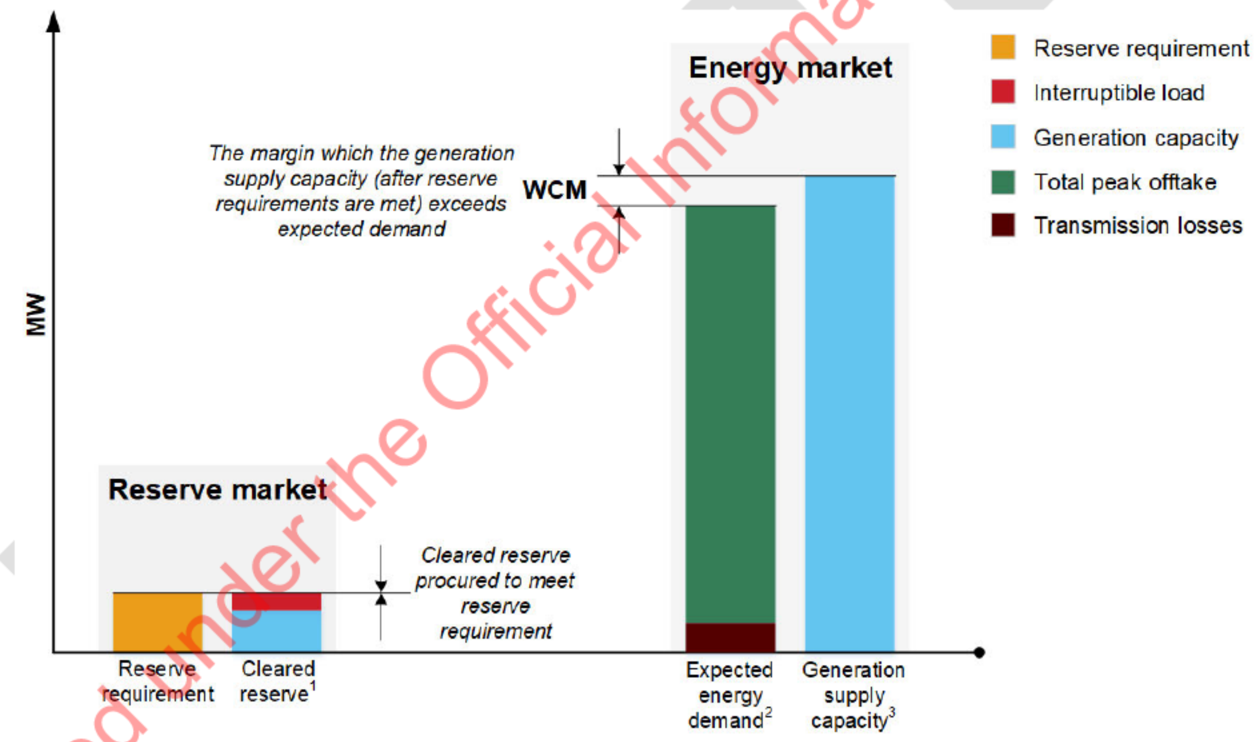
The method calculates the optimal supply excess within a secure electricity system

4.9 The method derives the economically efficient level of excess/surplus supply capacity for the electricity system operating at peak demand in its normal state. This means sufficient instantaneous reserve must be available. Typically that reserve covers an unplanned outage of either a single HVDC pole or the generator producing the most electricity.[27]

4.10 When the actual WCM is zero, expected demand equals expected supply capacity (i.e. expected demand is met with no margin) and the system operates with the required reserve cover. When the actual WCM is greater than zero, it represents the level of excess expected supply capacity above the expected demand after reserve requirements have been met.

4.11 Figure 5 illustrates how WCM relates to the components of the reserve and energy markets.

Figure 6: WCM in relation to the components of the reserve and energy markets



Source: Electricity Authority

Notes:
1. Cleared reserve consists of interruptible load, and generating capacity in the form of tail water depressed, and partially loaded spinning reserve.
2. Expected energy demand is the expected offtake from the grid and networks in the North Island during the top 500 trading periods during winter. Transmission losses including HVDC losses are added.
3. Generation supply capacity is the available generation supply after reserve requirements of

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[27] The system operator categorises the types of events that it will procure reserves to cover in its Credible Event Reviews. Those reviews take an economic/actuarial approach to covering events. Once the events are categorised, the system operator procures reserves to cover the largest event in each trading period. If supply is insufficient to meet demand (including the reserve requirement), the system operator undertakes load shedding in accordance with the security policy of its policy statement.

the system are met.

4.12 There are two key advantages to separating reserve from the WCM in this way:

(a) It means the margin is a measure of the economically efficient surplus of supply (i.e. true ‘surplus’) to hold in the system distinct from any required generation capacity surplus to meet reserve requirements. The standards are not in place to assess the efficiency of procuring reserve.

(b) It means the system operator can use the most up-to-date assumptions for both the reserve requirement and interruptible load. That is, the interruptible load capacity and reserve requirement are not baked into the margin itself; they are inputs into the evaluation.

4.13 Changes in the current and proposed capacity standard arising from the treatment of reserve requirements in the method are discussed in paragraphs 5.38-5.40.

The deterministic method used accounts for variability in supply and demand

4.14 An improved modelling method has been applied which takes a deterministic approach using actual demand and generation data to account of variability of demand and supply.

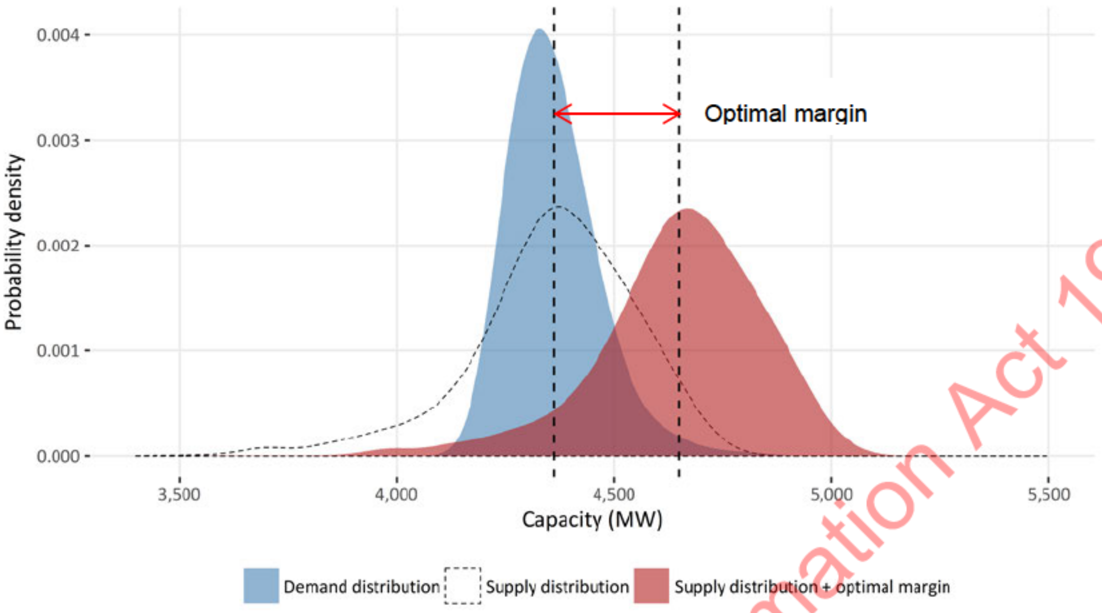
4.15 In 2008 and 2012 the WCM standard was calculated using a model that used a Monte Carlo simulation and the randomised application of generation data for the different technology types. The new approach is expected to be superior to the previous model as it is no longer dependent on the choice of random data that was applied.

4.16 Figure 6 highlights the distribution of demand and adjusted supply distributions from 2017 data for the top 500 demand trading periods. The spread in the supply distribution is driven by intermittent generation, mostly wind.

4.17 The dashed outline supply distribution represents supply with its full variability and with enough thermal generation removed so that expected supply meets expected demand. This situation represents a WCM of zero. If we take an example of a trading period where demand is equivalent to expected demand, then we know this demand will be met provided supply is at or above its expected level.

4.18 Clearly, a WCM of zero is not likely an optimal solution as there are many demand trading periods that could occur that when matched with supply from a trading period that could occur will lead to a shortage situation. The modelling method progressively shifts the supply curve to the right by adding fixed generation until an optimal system cost is achieved. This optimal point is represented by the red supply distribution.

Figure 7: Demand and adjusted supply distributions for 2017



Source: Electricity Authority

Notes:
1. The blue distribution represents demand during the top 500 trading periods.
2. The dashed outline distribution is a supply distribution adjusted by removing thermal generation so that expected supply equals expected demand.
3. The red distribution represents the supply distribution shifted to the right by the optimal margin.
4. The area under each distribution equals one.

4.19 In addition to providing improved outputs, the new model has been developed directly by the Authority and can be readily adapted. The 2012 analysis was undertaken on a proprietary model that was not made available to the Authority for further use and development. The new model has been independently verified and published.

The top 500 demand trading periods are used to model supply and demand

4.20 It's important that the supply and demand variability is appropriately represented within the modelling. The new methodology models supply and demand using data from the 500 trading periods with the highest demand in 2017. The current standards and ASA model demand based on the top 200 trading periods for demand and use a variety of approaches for modelling supply.

4.21 Using the same number of trading periods to inform the modelling of supply and demand levels and variability is the best way to create a consistent comparison of supply and demand that reflects the operation of the electricity system during peak periods.

4.22 The number of trading periods chosen must be sufficiently high to:

(a) capture all the trading periods in which it is efficient to shed demand rather than build additional generation

(b) accurately represent the *distribution* of output from intermittent generation source (such as wind) that may occur during peak periods.

4.23 Testing of alternative numbers of trading periods showed that 500 trading periods was sufficient to represent the distribution of output by wind generation, whereas 200 trading periods was not optimal. Testing showed that 1000 trading periods was also sufficient, but did not materially improve the resolution of the distribution to justify further complexity in the methodology.

4.24 The use of only the top 200 trading periods results in a higher expected peak demand and, as a result, a lower calculated standard than when using 500 trading periods. The differences between the current and proposed standards are discussed in paragraphs 5.38-5.41.

The modelling uses up-to-date assumptions

4.25 The modelling of the base case scenario reflects the 2017 electricity market environment. The modelling captures a range of factors including:

(a) Demand factors:

  (i) demand and demand variability at peak

  (ii) system losses at peak

  (iii) shortage costs

(b) Supply factors:

  (i) generation capability from flexible generating plant, including controlled hydro and thermal plant and associated forced outage rates

  (ii) generation contribution from inflexible generating plant including run-of-river hydro, geothermal, and cogeneration

  (iii) generation contribution from intermittent generating plant including wind and other embedded generation (or injection from batteries)

  (iv) sustained instantaneous reserve (SIR) requirements

(c) Transmission factors:

  (i) constraints affecting inter-island transfer

  (ii) forced outage rates on the HVDC.

4.26 Key assumptions are summarised in Table 5.

4.27 All of the assumptions are described in more detail in the modelling assumptions companion paper and the relevant assumption are also summarised in the draft update of the SSAD provided as Appendix C. Publishing the revised SSAD would require the system operator to apply these assumptions in the ASA, unless it was able to demonstrate a rationale for doing otherwise.

Table 5: Key input assumptions for WCM calculations

Issue	Base case assumption
Demand factors	Shortage costs as set out in paragraphs 5.32 to 5.35

Issue	Base case assumption
Supply factors	Existing generation: • 2017 generation fleet available with some thermal removed (approximately 1000MW removed) as explained in note 1 to this table • Forced outage rates of 3% (thermal) and 2% (hydro) controlled generation • Probability curves for all other generation (using actual output data from 2013-2017 where available) Additional generation capacity: • Approach as set out in paragraphs 5.29-5.31 • Modelled as reciprocating diesel engines with costs from the MBIE EDGS report[28]
Reserve requirement	400 MW of SIR, of which: • 260 MW is from generation capacity • 140 MW is from interruptible load FIR is excluded (as per Table 6)
Transmission factors	Full HVDC bi-pole available at 1,050 MW northward transfer capacity

Source: Electricity Authority

Notes: 1. The base case removes 1000 MW of existing thermal capacity to ensure situations are modelled where significant shortage costs arise. The method then progressively adds back thermal generation, with the cost characteristics of reciprocating diesel engines. Those cost characteristics may be higher than the sunk costs of existing thermal generation, however we are unable to make any evidence-based assumptions about the costs of such existing generation.

4.28 Factors excluded from the modelling are presented in Table 6 below.

Table 6: Factors excluded from WCM modelling

Type of factor	Factor	Rationale for exclusion

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[28] The Ministry of Business, Innovation and Employment's (MBIE) 'Electricity Demand and Supply Generation Scenarios 2016' (EDGS), November 2016. Available at http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/documents-image-library/edgs-2016/generation-cost-assumptions.xlsx.

Type of factor	Factor	Rationale for exclusion
Demand factors	Unserved energy resulting from an extended contingent event (ECE) or catastrophic event	The system operator's credible event review is the process that determines the economically efficient approach to covering power system events. The WCM modelling assumes the power system is operating in normal security conditions.
Supply factors	Generation 'unit commitment' and other market behaviours	WCM is a measure of physical capacity based on the assumption that an available plant will be committed and offered as required
	Planned generation outages	These can be scheduled at times when capacity is not scarce
	Shortages of fuel or water	WCM is not an index of adequacy of dry-year reserve. Fuel constraints are also not expected to constrain peak generation output significantly, but if this became a possibility, it could be accounted for in the ASA
	Fast instantaneous reserve requirements	Sustained instantaneous reserve (SIR) is modelled and assumed to bind first
	Frequency keeping requirements	During a North Island winter peak the energy and reserve price are assumed to be sufficiently high to motivate plant to be offered for reserve and/or energy rather than frequency keeping. Under these circumstances frequency keeping is most likely to be provided by South Island generation via the HVDC link. The link, as modelled, has sufficient capacity to accommodate the frequency keeping requirement.
	Ramping constraints on thermal plant	Expected to be able to be managed through dispatch processes
Transmission factors	AC outages and constraints	WCM is an index of island-level adequacy and does not consider regional issues

Source: Electricity Authority

Additional generation is modelled as though it is thermal

4.29 The cost assumptions for additional generation provided in Table 5 effectively assume that any additional generation required is a diesel-fuelled reciprocating engine. Modelling with diesel-fired generation represents an investment in generation that is optimised solely to meet peak demand.

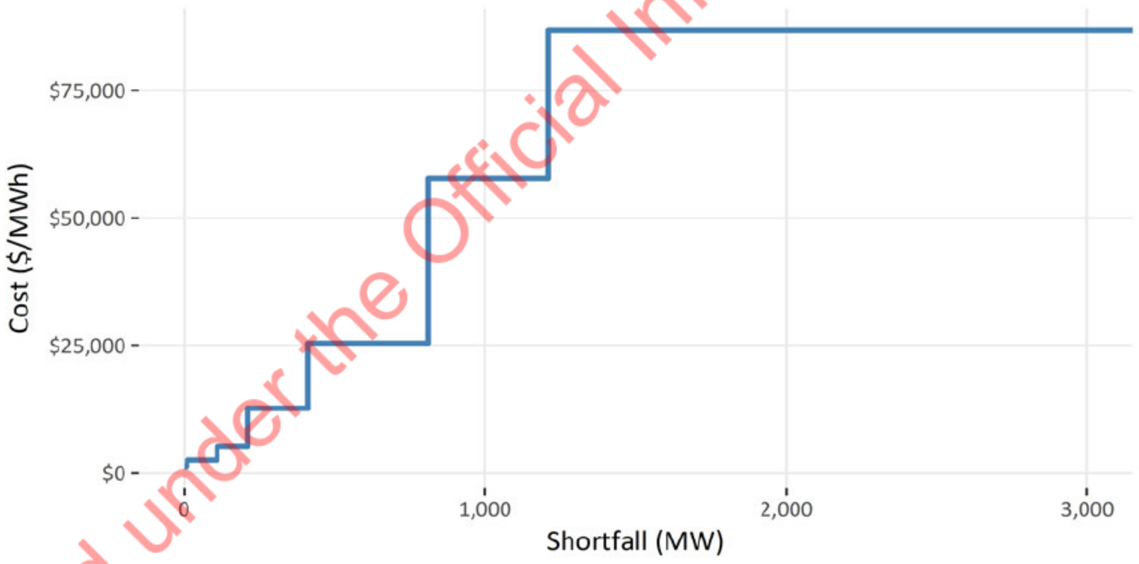
4.30 Diesel engines are likely to be a relatively expensive source of generation, increasing the reserve cost and, consequentially, the total system cost in the modelling. In practice, in the current environment, natural gas-fired open-cycle gas turbines (OCGTs) appear to be the most likely choice for large-scale (i.e. > 50 MW) new generation, with various resource consents in place to enable them to be built if required.

4.31 As noted in the discussion on the assumptions used in the WEM analysis, the assumption that additional generation will be thermal may be less appropriate in the future. Scenarios with different reserve costs have also been modelled so that the standards reflect a conceivable range of outcomes (these scenarios are discussed in paragraphs 5.43-5.48).

Existing assumptions for value-of-lost-load have been applied

4.32 The shortage cost curve applied in the model is illustrated in Figure 7 and detailed in Table 7. This is the same cost curve that was used in the 2008 analysis, adjusted upwards for inflation.

Figure 8: Shortage cost curve for WCM



Source: Electricity Authority

Table 7: Tranches of shortage cost for WCM

Tranche #	Shortfall (MW)	Shortage cost ($/MWh)
1	0-10 MW	$1,270/MWh
2	10-110 MW	$2,540/MWh
3	110-210 MW	$5,090/MWh
4	210-410 MW	$12,700/MWh

Tranche #	Shortfall (MW)	Shortage cost ($/MWh)
5	410-810 MW	$25,400/MWh
6	810-1210 MW	$57,800/MWh
7	1210+	$86,700/MWh

Source: Electricity Authority

4.33 Although there has been some investigation into the cost of shortage since 2008, there is no clear evidence to justify further revision of the curve.

(a) As noted in the discussion on the assumptions applied in the analysis of the WEM, Transpower is in the process of making new estimates of the value-of lost-load (VoLL) based on feedback received from industry participants. This revised data was not available while this paper was being prepared.

(b) In the event this new data is made available prior to the Authority's decision on these proposed Code amendments, the Authority intends to consider whether and how to apply that data in setting these standards.

4.34 Looking further ahead, the widespread uptake of battery storage or other technologies that support consumer resilience and enable peak load management could significantly alter the costs associated with a shortage of capacity, or the costs of peaking capacity itself, and the applicability of the capacity standard. This issue is discussed further in section 6 of this paper.

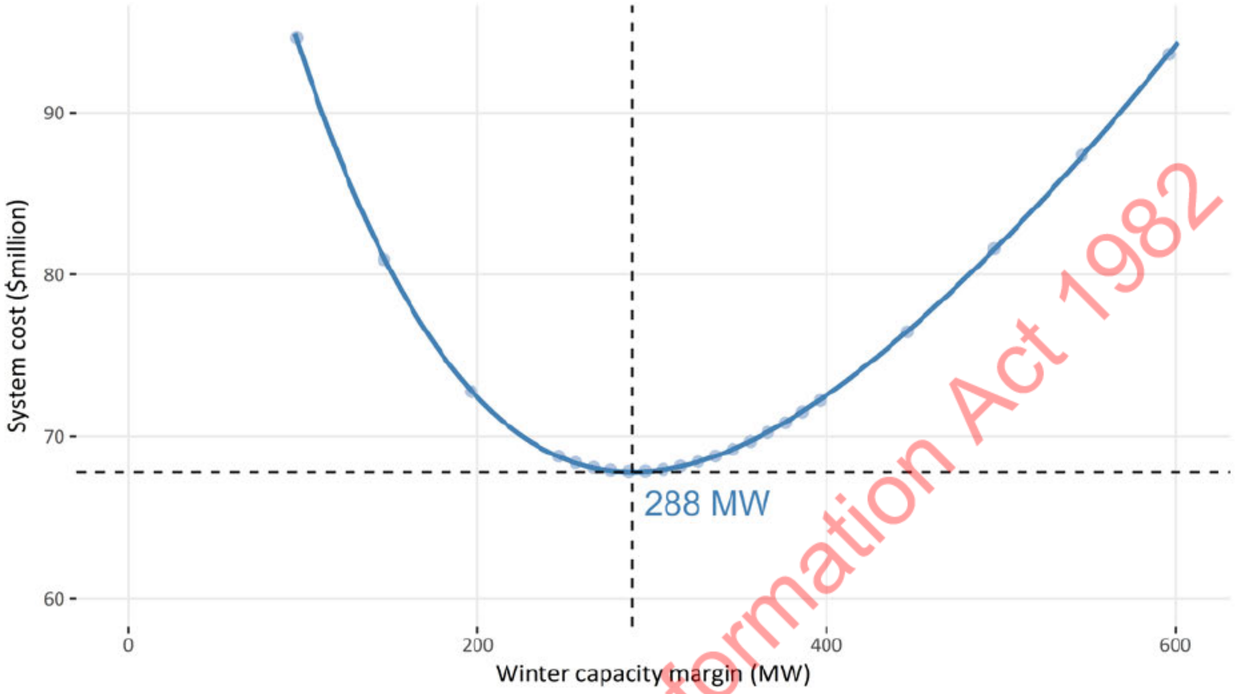
4.35 Consumers already face quite different costs from lost supply depending on how they use electricity, and this distribution of costs is only likely to expand with the uptake of new technologies. To accommodate this, scenarios with lower and higher costs of lost supply have also been modelled so that the standards reflect a conceivable range of outcomes (these scenarios are discussed in paragraphs 5.43 - 5.48).

The base case shows an optimal WCM of 288 MW

4.36 The base case analysis indicates an optimal level of WCM of 288 MW.

4.37 The trade-off between the shortage cost and the generation cost is shown in Figure 8. Note that small variations in the level of WCM (i.e. from 200-450 MW) have relatively insignificant impact on the system cost.

Figure 9: Base case optimal level WCM



Source: Electricity Authority

Comparisons between the proposed and current WCM are complex

4.38 The current WCM has a base case optimum of 690 MW. A superficial comparison against the proposed 288 MW may appear to be an alarming decrease but this actually represents an effective increase in the surplus of generation that it is efficient for the system to have.

4.39 There are two main changes to the methodology that also help explain the observed reduction in WCM:

(a) the treatment of reserve requirements

(b) the change from 200 to 500 peak trading periods.

4.40 The change to the treatment of reserves and interruptible load is the single biggest reason for the nominally large change in WCM.

(a) In the 2018 modelling:

(i) The WCM represents an economic level of surplus generating capacity in an operating system where all reserves are met.

(ii) Interruptible load of 140 MW contributes to meeting the reserve requirement of the system which is 400 MW. Interruptible load can free up tail water depressed or spinning reserve (generation capacity) to meet demand but cannot contribute to meeting demand itself.

(b) In contrast, in the 2012 modelling:

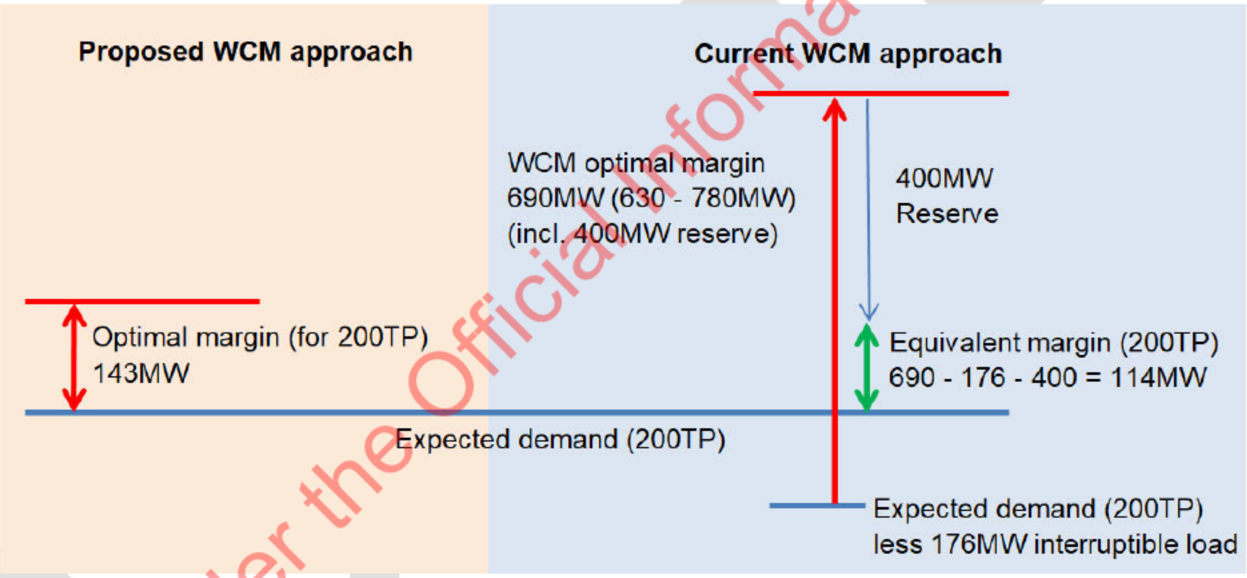
(i) The WCM represents the optimal capacity of generating plant above the expected demand reduced by interruptible load. However, this representation combines the economic capacity surplus with the reserve requirement to operate the system.

(ii) The 2012 modelling effectively assumed that all reserves were provided by generation and that reserves could be reduced (with an associated cost) before load was not served.

(iii) Expected demand was reduced by 176 MW to account for interruptible load and some demand response. This meant that the cost of not serving this load did not appear in the resulting system cost curve used to find the optimal margin.

(c) Figure 9 shows a side by side comparison of the 2018 and 2012 WCM modelling approaches for 200 peak trading periods used to derive the current standard. Adjusting the current WCM of 690 MW to account for reserve and interruptible load in a consistent manner with the proposed approach provides an equivalent margin (green arrow) of 114 MW compared to 143 MW in the proposed approach (when applied to 200 trading periods).

Figure 10: Comparison of proposed and current WCM for 200 peak trading periods



Source: Electricity Authority

4.41 The other significant difference in the margin is the increase from 200 to 500 peak trading periods that are modelled and define the margin.

(a) In the 2018 modelling:

(i) the number of peak trading periods was increased from 200 to 500 to better describe the distribution of supply capacity at peak.[29] In particular, this assists in describing the contribution at peak from intermittent generation such as wind and small embedded generation or injection by using historical observation.

(ii) the demand distribution is described by 500 trading periods in the same way as the supply distribution. In addition, the WCM is the margin by which

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[29] As discussed earlier in paragraphs 5.20-5.24

expected supply exceeds expected demand of the 500 trading periods. Clearly the expected value of peak demand in the top 500 trading periods is lower than the expected demand in the top 200 trading periods. This change to 500 trading periods acts to increase the margin although it is now represented above a lower expected demand figure. In the base case this shift accounts for 91 MW increase in the margin.

(b) By comparison, in the 2012 modelling:

  (i) 200 trading periods for peak demand and (most) supply assumptions. The WEM margin is the margin by which expected supply (including supply cleared to meet reserve) exceeds the expected demand in the top 200 trading periods less a 176 MW reduction to account for interruptible load and some demand response.

  (ii) due to limited availability of wind data, a combination of actual and synthetic wind generation output was used to produce an averaged wind contribution factor.

4.42 As discussed in paragraphs 2.9-2.12, there have been significant changes to electricity assets and markets since 2012. However, given the proposed decrease is largely explained by the factors set out in paragraphs 5.40-5.41 above, the net effect of those changes has been minimal on the efficient standard.

4.43 The 2018 modelling has produced a result that is, in effect, quite similar to the current WCM standard. The effect is an ~30 MW increase in the 2018 base case optimum for a range of 660-810 MW, on the basis of a like-for-like comparison assuming:

(a) reserves and interruptible load were treated consistently with 2012

(b) expected demand was referenced to the top 200 trading periods

(c) a 150 MW spread between the lower and upper bounds of the range.

The sensitivity of WCM has been modelled

4.44 As noted in the modelling assumptions companion paper, a range of sensitivity analyses have been run to test their impact on the WCM calculation. These sensitivities test whether the proposed standards are set at the appropriate level, rather than testing whether the proposed standard is sufficient to accommodate the sensitivity scenarios. The scenarios include:

(a) Demand sensitivities:

  (i) increased demand (+2% and +5%) without any corresponding change in the base case generation fleet

  (ii) increased and decreased shortage (VoLL) costs (±10%).

(b) Supply sensitivities:

  (i) increased capital costs for additional generation (10% and 50% increases)

  (ii) all new additional generation as open-cycle diesel turbines, as opposed to reciprocating diesel engines

  (iii) increased thermal outage rates (rate of 10%, as opposed to 3% in the base case)

  (iv) doubling the wind generating capacity in the generation fleet

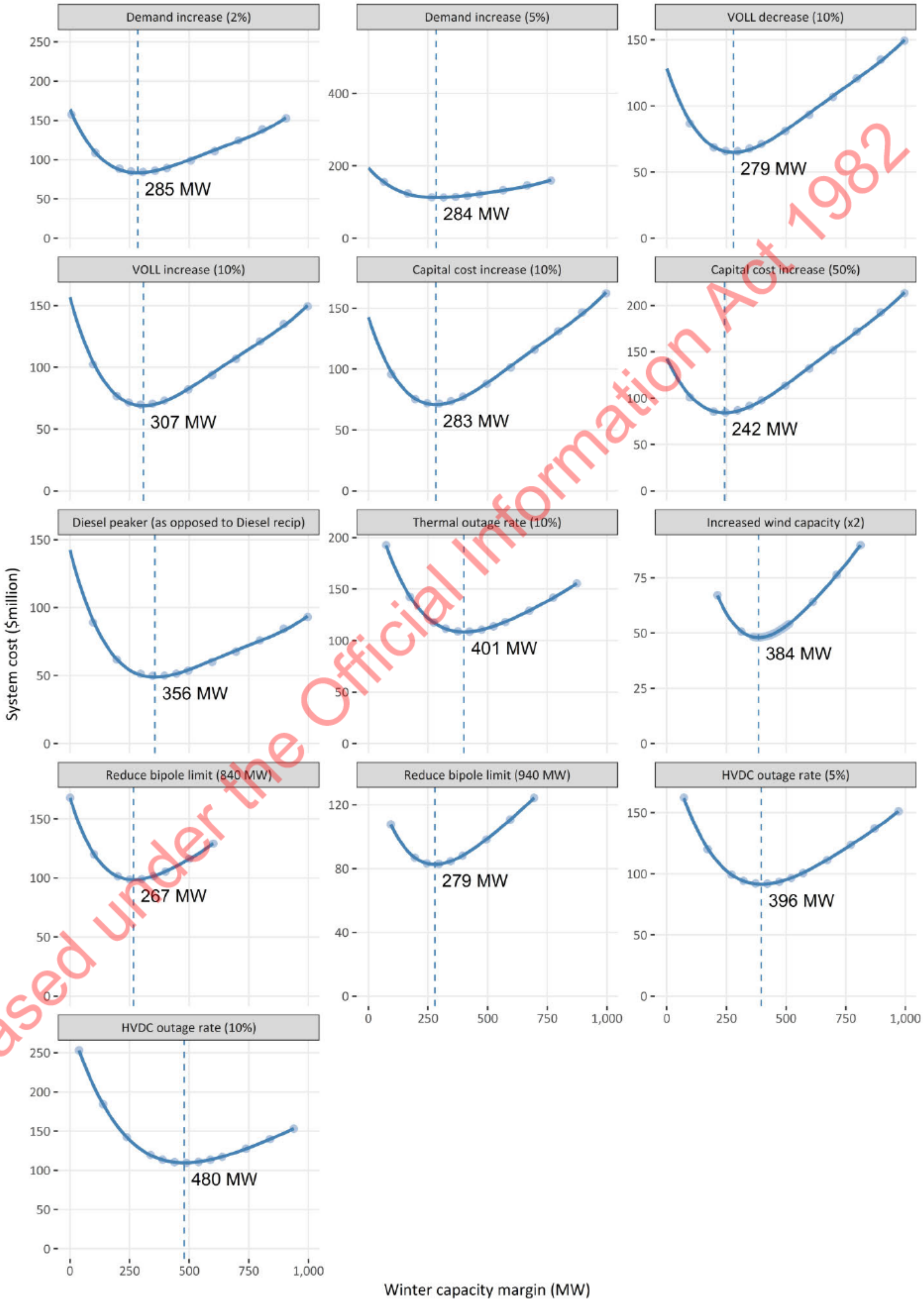
(c) Transmission sensitivities:

   (i) increased HVDC outage rates (rates of 5% and 10%, as opposed to a 1% chance of having at least one pole unavailable in the base case)

   (ii) reduced HVDC transfer capacity (840 MW and 940 MW limits), with consequential constraints in the contribution of South Island generation.

4.45 The effects of various sensitivity cases on the optimal WCM are shown in Figure 10.

Figure 11: Optimal WCM under various sensitivities



Source: Electricity Authority

4.46 The analysis showed that the optimal WCM is reasonably insensitive to most of these uncertainties. Several other scenarios also showed materially higher total societal costs than the base case, but did not result in margins outside the optimal range identified in the base case (i.e. they fell within the range of 200–450 MW).

4.47 Of the sensitivities that fall within that range, the use of open-cycle diesel turbines seems the most credible. That sensitivity likely better represents actual generation investment patterns, which are made with a much broader range of considerations than exist in the WCM modelling. The use of diesel reciprocating engines represents the efficient investment for the next 10 MW of supply, as if supplying that peak 10 MW was the only reason to invest. The Authority may, after receiving submissions, recalculate the WCM standard using a combination of open-cycle diesel turbines for every complete block of (say) 50 MW and reciprocating diesel engines for any 10 MW increments up to 40 MW.

4.48 The only scenarios that caused the WCM to fall outside that range were:

(a) HVDC outage rates of 10% (resulting in a WCM of 480 MW)

(b) a thermal outage rate of 10% (compared to 3% in the base case, resulting in a WCM of 401 MW).

4.49 Neither of these scenarios appear sufficiently credible at the current time to justify being used to set the WCM range.

Additional wind must be de-rated in the calculation of actual WCM

4.50 The current variability of supply is accounted for within modelling to produce the proposed standard. The approach taken uses the probability distribution derived from historical data during the top 500 trading periods. A sensitivity ('increased wind capacity (x2)' in Figure 10) highlights that the standard is sensitive to the addition of intermittent generation.

4.51 To ensure an apples to apples comparison can be made by system operator's assessment (or forecast) of the actual WCM against the standard, intermittent generation must be de-rated. This adjustment is required to avoid an actual WCM being calculated that includes a greater probability of unserved demand (and therefore shortage cost) than was implicit in the standard.

4.52 The Authority has devised a method to adjust additional wind based off the expected value it contributes at peak.

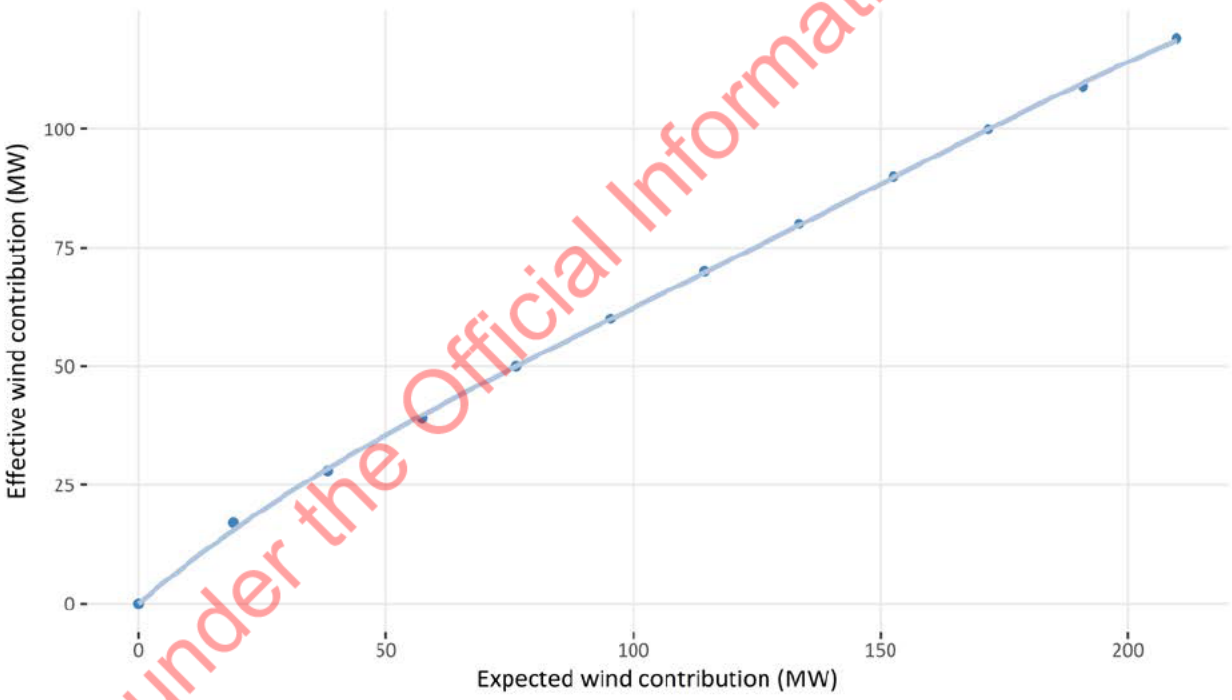
(a) Prior to actual data from a wind farm being available to system operator, they should assume a supply distribution based on the current wind fleet, unless they have better information. Once the fleet has operated for a winter, then actual data will be available. This will provide an expected contribution from the generating plant.

(b) The Authority has devised a relationship between this expected value, and a smaller effective contribution, that is consistent with the proposed standard. This has been achieved by incrementally scaling the existing wind fleet and deriving an optimal WCM for each stage of scaled wind. The effective contribution factor is then derived to scale back the expected contribution and provide a WCM comparison that is relevant to the proposed standard.

(c) Deriving the effective contribution from the expected contribution rather than nameplate capacity ensures that a real probability distribution from the wind farms can be incorporated into the results. For example a wind farm where generation *never* coincides with the top 500 demand periods will have an expected contribution of zero, and also an effective contribution of zero.

4.53 Figure 11 illustrates the relationship between effective contribution and expected contribution for additional wind generation that will be set out in the SSAD. A similar approach will be taken for any other inflexible and intermittent generation that adds significant variability to supply.

Figure 12: Effective contribution from additional wind generation



Source: Electricity Authority

Notes: For example: A new wind farm of 130 MW nameplate capacity might have an expected contribution of 50 MW (using the distribution defined by the current fleet) which would have an effective contribution to the WCM of 35 MW.

The Authority is proposing to change to the WCM standard and the SSAD

4.54 Based on the above analysis (including sensitivities), the Authority proposes that the capacity security of supply standard should be changed from 630-780 MW to 200-450 MW. The proposed Code change is set out in Appendix A of this paper.

4.55 The Authority considers the calculation methodology is appropriate and robust, and the assumptions are appropriately accurate. Furthermore, the Authority considers the methodology used is superior to the previous methodology, particularly with respect to the number of trading periods in the analysis and the treatment of reserves.

4.56 The Authority has revised the SSAD to ensure that it supports the system operator to make forecasts in its ASAs that are meaningful and consistent with the standard. The draft SSAD is provided at Appendix C.

4.57 The base case analysis indicates that the optimal WCM is around 288 MW. However, as with the 2012 analysis, the Authority prefers to acknowledge the uncertainty in the calculation of the optimal WCM by using a range-based standard. A "bright-line" standard may also fail to convey that there is a continuum of investment efficiency, instead suggesting a sudden transition from adequate to inadequate.

4.58 When choosing a range, the Authority has been guided by:

(a) the methods and associated ranges set out in Table 8 below, to connect the range to the modelled costs

(b) rounding results to multiples of 20 MW or 50 MW, so as to help users not infer more precision than actually exists

(c) the most credible results from the sensitivity analysis, such as additional generation being modelled as open-cycle diesel turbines as described in 5.43(b)(ii).

4.59 Table 8 below sets out the methods that the Authority has found useful when selecting a range for WCM. The Authority is likely to use its discretion, guided by these methods, when choosing a final range to be included in the Code. The Authority expects there are likely to be changes in the final range chosen because submitters will identify improvements to the overall calculation methodology and/or the input assumptions, such as the results of Transpower's VoLL study becoming available.

Table 8: Guiding methods for selecting and rounding a range for WCM

Methods	Associated range	Rounding to the nearest 20 MW or 50 MW
$5M above the base case optimum cost	196-404 MW	200-400 MW (both)
$10M above the base case optimum cost	162-460 MW	160-460 MW (20) 150-450 MW (50)
2.5% above the base case optimum cost	232-353 MW	240-360 MW (20) 250-350 MW (50)
5% above the base case optimum cost	211-382 MW	220-380 MW (20) 200-400 MW (50)

Source: Electricity Authority

Notes:
1. The base case optimum system cost is $67.8 million. This is the total of (a) short run marginal cost for generation; (b) capital cost of additional capacity; and (c) shortage cost of unserved load.
2. All system costs have been drawn from the line of best fit from the base case (not from any individual result from the modelling).

4.60 When interpreting the proposed range, a WCM:

(a) below the lower standard of 200 MW would indicate an inefficiently low level of investment (where the cost of adding more supply would be justified by the reduction in shortage costs at times of insufficient capacity)

(b) between 200 and 450 MW would indicate a roughly efficient level of investment (subject to key uncertainties in determining the optimal point)

(c) above the upper standard of 450 MW would indicate a level of investment that was higher than efficient in terms of the trade-off between supply costs and the cost of shortage at times of insufficient capacity (but might still be efficient for other reasons).

4.61 The Authority is engaging with the system operator about whether the change in the model used for calculating the WCM will have implications for their monitoring activities, including the ASA. Consequential changes may also be required to the SOSFIP. If so, those changes will be pursued through the process set out in the Code.

Q4. Do you agree that the WCM security of supply standard should be revised to 200–450 MW? If not, why not?

5 The process for calculating the standards may need to change to reflect the dynamic market environment

Electricity supply and demand are increasingly dynamic and uncertain

5.1 There has been significant change in the make-up of New Zealand's generation fleet in the six years since the 2012 review, with clear signs that further change can be expected in the years ahead.

(a) Thermal generation plant at Otahuhu and Southdown were closed

(b) Market arrangements were put in place to enable the remaining two Rankine units at Huntly to remain in operation after it was signalled that these might also be shutdown. Those units are also now in the process of transitioning away from the use of coal and natural gas to operate only on gas.

(c) The Taranaki natural gas combined cycle plant has undergone a major refurbishment, but its future beyond about the next five years is uncertain.

5.2 The Mill Creek wind farm is the only new generating asset to have commenced operation over since 2012, and no large generating assets are currently under development.

5.3 These changes in the generation mix reflect that demand growth has remained relatively flat, and future growth is uncertain. Actual capacity and energy margins have exceeded the standards over this period and are forecast to do for several more years. The system operator's most recent ASA forecasts the earliest need for investment as 2021, where a "low carbon and electrification" scenario could see the capacity margin fall below the existing standard.

5.4 Forecasting the 5-to-10-year period covered by the ASA relies on a wide range of assumptions around both electricity supply and demand. Changes in technology, and expected changes in the government's climate change policy mean that these assumptions now have much higher degrees of uncertainty than they did in the past.

5.5 From a technology perspective, the cost curves for consumer and renewable energy technologies such as solar PV, batteries and large-scale wind power continue to decline at a relatively fast rate, increasing their commercial viability.

5.6 At the same time, the Authority is pursuing a range of initiatives, such as the reform of distribution network pricing that are expected to influence investment and operating decisions, and the government is also investigating changes to climate change policy and in other related policy areas. Taken together, these changes are expected to further increase the relative merits of renewable generation and demand-side participation in the electricity market.

The existing standards and processes may not be robust into the future

5.7 Many of the assumptions used in the methodology and calculation of the standards could be affected by these changes.

5.8 Perhaps the most material of these, on WCM, is the impact of storage technologies:

(a) Continued declines in the cost of storage could lead to it becoming the lowest-cost option for meeting peak demand. In that case, it would replace reciprocating diesel engines in any recalculation of WCM.

(b) Widespread adoption of storage technologies could fundamentally change the way that peak electricity demand is met. A consumer with a battery at their premise might become oblivious to power outages shorter than the time it takes their battery to discharge.

(c) In summary, (a) could flatten the up-slope of the WCM base case (the slope to the right of the optimum), tending to make it efficient to have a higher WCM standard.[30] Meanwhile, (b) could flatten the down-slope of the WCM base case (the slope to the left of the optimum), tending to make it efficient to have a lower WCM standard.[31] Taken together, these effects could flatten, and reduce the scale of, the curve so much that the efficient range around the optimum becomes very large. A large range might be easily achieved and require an alternative approach to monitoring.

5.9 Another source of major change could be government climate change policy.

(a) Such policy might—directly or indirectly—have the effect of

(i) reducing the contribution of thermal generation

(ii) increasing the contribution of renewable generation.

(b) The calculation of NZ-WEM has been modelled as though it is primarily a scheduling problem for hydro and thermal. In future, that might become a problem of optimising hydro, thermal and wind. If thermal plays a diminishing role, an alternative approach to monitoring may be warranted.

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[30] Similar to the 'fuel cost decrease (20%)' NZ-WEM sensitivity in Figure 3.

[31] Similar to the 'VoLL decrease (50%)' NZ-WEM sensitivity in Figure 3.

5.10 Looking ahead to these potential changes, this review becomes a useful opportunity to consider the future role of the standards and margins. Will they continue to be valid measure of security of supply? If so, what changes might be required to the methodologies and assumptions? And how often do the margins need to be recalculated? Reviewing every 5-6 years, as has been the case to-date appears likely to be too infrequent to keep pace with change.

5.11 Options include:

(a) requesting the system operator to recalculate the standards as well as the actual margins themselves on an annual basis (or other, more regular frequency)

(b) the continued evolution and development of their scenario and sensitivity analysis.

5.12 The use of sensitivities and scenarios also appears to be important, given the range of potential 'futures'. The system operator already now considers a range of potential scenarios when completing the ASA.

5.13 While there is no evidence to suggest the need for change is imminent, the Authority is interested in receiving feedback and comments on the future of the standards and margins as part of this consultation process.

Q5. When do you consider the Authority should next review these standards and the associated methodologies?

Q6. What changes do you expect to be required to the medium-term monitoring of security of supply over the next few years, and how do propose these be implemented?

6 We have prepared a regulatory statement for the proposed amendment

6.1 Section 39(1)(b) and (c) of the Act requires us to prepare and publish a regulatory statement on any proposed amendment to the Code, and to consult on the proposed amendment and regulatory statement.

6.2 Section 39(2) of the Act provides that the regulatory statement must include:

(a) a statement of the objectives of the proposed amendment

(b) an evaluation of the costs and benefits of the proposed amendment

(c) an evaluation of alternative means of achieving the objectives of the proposed amendment.

6.3 This section contains the regulatory statement for a proposed Code amendment.

The proposed amendment

6.4 The Authority proposes to amend the Code to:

(a) change the national energy security of supply standard (NZ-WEM) from a range of 14-16% to a range of 12-19%

(b) remove the South Island energy security of supply standard (SI-WEM)

(c) change the capacity security of supply standard (WCM) from a range of 630-780 MW to a range of 200-450 MW.

6.5 The drafting of the proposed amendment is contained in Appendix A.

The objective of the proposed amendment is to improve the standards

6.6 The objective of the proposed amendment is to provide industry stakeholders with a reference measure of security of supply that better reflects an efficient level of generation investment, given the mix of generation, demand, and transmission that is expected to be in place over the next few years, and acknowledging key uncertainties.

Q7. Do you agree with the objectives of the proposed amendment? If not, why not?

The benefits of the proposed amendment are expected to outweigh the costs

6.7 The proposed amendment has no cost other than the transactional costs incurred in the consultation, and the cost for gazetting code amendment notices (if the proposal is approved).

6.8 The proposed amendment has benefits through providing a more accurate benchmark of efficient investment in generation and inter-island transmission, which may help to avoid:

(a) an inefficiently high level of generation investment

(b) unwarranted concern from stakeholders about the level of security of supply risk

(c) an inappropriate policy response to a perceived risk of generation inadequacy.

6.9 The base case analysis for each of the standards shows that an inefficient level of generation investment can incur a societal cost in the tens of millions of dollars per year.

6.10 Although the identified benefits are qualitative, rather than quantitative, it appears highly likely that these benefits will materially exceed the relatively minor costs.

Q8. Do you agree the benefits of the proposed amendment outweigh its costs?

We have identified four other means for addressing the objective

6.11 The Authority has identified four other means for addressing the objective:

a) The standards could reflect only the base case scenario, with no consideration of sensitivities or uncertainties.

b) Alternative modelling techniques, methodologies and assumptions could be applied to calculate the standards.

c) The Authority could determine not to specify the standards in the Code, but continue to require the system operator to calculate the margins. Participants could then make their own judgement as to the risks associated with these margins.

d) The Authority could elect not to require the standards and margins to be calculated, instead relying on industry participants to make their own calculations and judgements of security of supply risks.

The proposed amendment is preferred to other options

6.12 We have evaluated the other means for addressing the objectives and prefers the proposal.

6.13 The use of only the base case is likely to create the perception that there is clear, and very accurately defined point at which security of supply risks start to materially increase. In practice, the uncertainties in the methodology and assumptions make the accurate calculation of the standards impossible.

6.14 The uncertainties inherent in the assumptions means that it is unlikely that any alternative method will provide an outcome that is more accurate. Given that the standards only provide a common, industry-wide reference, and do not drive any decision-making, a methodology with even higher accuracy is not warranted.

6.15 While having the system operator calculate both the standards and margins on a regular, on-going basis might ultimately be the process that is appropriate (as discussed in section 6), continuing to have the standards set in the Code, at least for the time-being, provides confidence through having:

(a) the derivation of the standards (ie. the policy) and the monitoring (ie. the operations) undertaken by separate parties

(b) the Authority's proposal to amend the standard tested by stakeholder consultation being operationalised

(c) revised and improved standards in place in time for the system operator's 2019 ASA.

6.16 Not specifying any standards at all, and requiring all participants to make their own judgement disadvantages those participants that do not have the resources to undertake such an evaluation. It also increases the risk that concern about security of supply risks results in an inappropriate and unnecessary political intervention (for example, the government of the day requiring the regulator to invest in reserve generation).

6.17 Given that the standards do not result in any specific regulatory decision-making, and that the only parties directly affected are the Authority and its service provider, the system operator establishing new standards is considered to be a discretionary matter for the Authority. The Authority may choose to consult on establishing new standards if the cost and effort of undertaking a full consultation process appears warranted.

Q9. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

The proposed amendment complies with section 32(1) of the Act

6.18 The Authority's objective under section 15 of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

6.19 Section 32(1) of the Act says that the Code may contain any provisions that are consistent with the Authority's objective and is necessary or desirable to promote one or all of the following:

Table 9: How proposal complies with section 32(1) of the Act

(a) competition in the electricity industry	The proposed amendment supports competition through making security of supply information that more accurately represents the market situation available to *all* participants, regardless of their capability to undertake similar analysis.
(b) the reliable supply of electricity to consumers	The proposed amendment supports the reliable supply of electricity to consumers by helping to signal the need for efficient generation investment.
(c) the efficient operation of the electricity industry	The proposed amendment supports efficiency through supporting the achievement of a level of supply security that appropriately balances the risks of loss of supply against the costs of over-investment.
(d) the performance by the Authority of its functions	The proposed amendment will enhance the performance of the Authority's monitoring function and inform its regulatory decision-making.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

Q10. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

We have given regard to the Code amendment principles

6.20 When considering amendments to the Code, the Authority is required by its Consultation Charter[32] to have regard to the following Code amendment principles, to the extent that the Authority considers that they are applicable. Table 2 (below) describes the Authority's regard for the Code amendment principles in the preparation of the proposal.

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[32] The consultation charter is one of the Authority's foundation document and is available at: http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/

Table 10: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposal is lawful, and is consistent with the statutory objective[33] and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The security of supply standards set out in the existing Code do not reflect an optimal or efficient level of security. The existing: • NZ-WEM overstates the amount of generation capacity required • SI-WEM is no longer a relevant security metric, as the conditions it seeks to monitor are very unlikely to exist in practice • WCM misrepresents the optimal or efficient level of security.
3. Net benefits are quantified	The extent to which the Authority has been able to estimate the efficiency gains is set out in the evaluation of the costs and benefits (see above). Key assumptions are set out in this paper, and a wide range of sensitivities have been considered.
4. Preference for small-scale 'trial and error' options	The proposed amendment is reversible. The Authority will continue to review and (if necessary) update the security of supply standards from time to time.
5. Preference for greater competition	No evaluation required – the preferred option has been clearly established.
6. Preference for market solutions	
7. Preference for flexibility to allow innovation	
8. Preference for non-prescriptive options	
9. Risk reporting	

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[33] The Electricity Authority promotes competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers

Appendix A Proposed amendment

7.3 Functions of the system operator in relation to security of supply and emergency management

(1) The **system operator** must—

(a) prepare and publish a **security of supply forecasting and information policy** that includes a requirement that the **system operator**—

(i) prepare and **publish** at least annually a security of supply assessment that contains detailed supply and demand forecasts for at least 5 years, which assists interested parties to assess whether the energy security of supply standard and the capacity security of supply standard set out in subclause (2) are likely to be met; and

(ii) consult with persons that the **system operator** thinks are representative of the interests of persons likely to be substantially affected by a security of supply assessment prepared under subparagraph (i) before **publishing** such an assessment; and

(iii) prepare and **publish** information that assists interested parties to monitor how hydro and thermal generating capacity, transmission assets, primary fuel, and **ancillary services** are being utilised to manage risks of shortage, including extended dry periods; and

(iv) **publish**, in connection with the information **published** under subparagraphs (i) and (iii), sufficient details of the modelling data, assumptions, and methodologies that the **system operator** has used to prepare that information as to allow interested parties to recreate that information (but without **publishing** information that is confidential to any **participant**); and

(b) implement and comply with the **security of supply forecasting and information policy** prepared and **published** in accordance with paragraph (a).

(2) For the purposes of subclause (1)(a)(i)—

(a) the energy security of supply standard is a **winter energy margin** of 12-19~~14-16~~% for New Zealand~~ and a **winter energy margin** of 25.5-30% for the South Island~~; and

(b) the capacity security of supply standard is a **winter capacity margin** of 200-450~~630-780~~ MW for the North Island.

(3) *No change.*

(4) *No change.*

(5) *No change.*

(6) *No change.*

Q11. Do you have any comments on the drafting of the proposed amendment?

Appendix B Format for submissions

Submitter	

Question		Comment
Q1.	Do you agree with the methodology and set of input assumptions applied in the WEM analysis and proposed to be included in the SSAD? If not, please identify which assumptions you disagree with and provide alternative assumptions, together with a rationale.	
Q2.	Do you agree that the NZ-WEM security of supply standard should be revised to 12%–19%? If not, why not?	
Q3.	Do you agree that the SI-WEM security of supply standard should be removed? If not, why not and how do you suggest a useful measure might it be determined?	
Q4.	Do you agree that the WCM security of supply standard should be revised to 200–450 MW? If not, why not?	
Q5.	When do you consider the Authority should next review these standards and the associated methodologies?	
Q6.	What changes do you expect to be required to the medium-term monitoring of security of supply over the next few years, and how do propose these be implemented?	
Q7	Do you agree with the objectives of the proposed amendment? If not, why not?	
Q8.	Do you agree the benefits of the proposed amendment outweigh its costs?	
Q9.	Do you agree the proposed amendment is preferable to the other options? If you	

	disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q10.	Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	
Q11.	Do you have any comments on the drafting of the proposed amendment?	

Appendix C Draft of revised SSAD

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ASA	Annual Security Assessment
Authority	Electricity Authority
CCGT	Combined Cycle Gas Turbine
Code	Electricity Industry Participation Code 2010
HVDC	High voltage direct current
IR	Instantaneous reserves
MBIE	Ministry of Business, Innovation and Employment
NZ-WEM	New Zealand Winter Energy Margin
OCGT	Open Cycle Gas Turbine
SI-WEM	South Island Winter Energy Margin
SOSFIP	Security of Supply Forecasting and Information Policy
SSAD	Security of Supply Assumptions Document
VoLL	Value-of-lost-load
WCM	Winter Capacity Margin
WEM	Winter Energy Margin

Appendix B Concept review of security margins modelling

www.concept.co.nz

Review of security margins modelling

Prepared for Electricity Authority

Version 1.3
6 June 2018

About Concept

Concept Consulting Group Ltd (Concept) specialises in providing analysis and advice on energy-related issues. Since its formation in 1999, the firm's personnel have advised clients in New Zealand, Australia, the wider Asia-Pacific region and Europe. Clients have included energy users, regulators, energy suppliers, governments, and international agencies.

Concept has undertaken a wide range of assignments, providing advice on market design and development issues, forecasting services, technical evaluations, regulatory analysis, and expert evidence.

Further information about Concept can be found at www.concept.co.nz.

Disclaimer

While Concept has used its best professional judgement in compiling this report, Concept and its staff shall not, and do not, accept any liability for errors or omissions in this report or for any consequences of reliance on its content conclusions or any material, correspondence of any form or discussions, arising out of or associated with its preparation.

Contents

Executive summary

The system operator publishes an annual assessment against the energy security of supply standard (energy standard) and capacity security of supply standard (capacity standard).

The purpose of the assessment is to determine whether New Zealand has enough generation to provide an efficient level of reliability – both in terms of managing dry-year risk and meeting peak demand.

The standards indicate the average level of spare generation on the system, both in terms of capacity and energy, that is desirable to cover contingencies such as power station breakdowns.

At present:

- the energy standard is a winter energy margin for New Zealand of 14-16% over expected national demand and a winter energy margin for the South Island of 25.5-30% over expected South Island demand
- the capacity standard is a winter capacity margin for the North Island of 630-780 MW over expected North Island peak demand.

The Electricity Authority (Authority) is currently reviewing these energy and capacity standards. As part of its review, it has used modelling to determine proposed new values for the standards.

The Authority has retained Concept to review the Authority's modelling. This report sets out the findings of Concept's review.

The Authority's work is not yet complete. So far, the main focus has been on the key modelling task of determining a 'threshold scenario' (i.e. the optimised scenario on which the margin is based). Accordingly, Concept's review focuses mainly on this task.

With regard to the modelling for the energy standards, Concept:

- considers that the formulation of the DOASA model used is fit for purpose
- has not been asked to check the code of the DOASA model
- agrees with the input assumptions, except where noted, and has checked that the inputs actually used in the modelling are consistent with the stated inputs
- has repeated one DOASA run and obtained identical results to the Authority
- raises some issues relating to the model formulation and assumptions, for consideration.

The Authority proposes to remove the South Island energy standard, leaving only the national energy standard. Concept agrees that this appears reasonable. Concept has inspected the supporting analysis at a high level and found no errors.

With regard to the modelling for the capacity standard, Concept:

- considers that the formulation of the R model used is fit for purpose
- has found no errors in the code or input assumptions
- has successfully reproduced the Authority's results
- raises some minor issues relating to the model assumptions, for consideration.

1 Introduction

Under Clause 7.3 of the Electricity Industry Participation Code 2010 (Code), the system operator publishes an annual assessment against the energy security of supply standard (energy standard) and capacity security of supply standard (capacity standard), where:

- the energy standard is a winter energy margin for New Zealand (NZ-WEM) of 14-16% over expected national demand and a winter energy margin for the South Island (SI-WEM) of 25.5-30% over expected South Island demand
- the capacity standard is a winter capacity margin for the North Island (WCM) of 630-780 MW over expected North Island peak demand.

These standards were last set in 2012.[1] The 2012 analysis was based on the following assumptions:

- the national energy standard was the level of NZ-WEM at which the marginal cost of adding dry-year backup generation equalled its marginal benefit in terms of reducing energy shortfall
- the South Island energy standard was the level of SI-WEM at which the marginal cost of adding dry-year backup generation *in the South Island* equalled its marginal benefit in terms of reducing South Island energy shortfall (assuming a surplus of North Island generation)
- the capacity standard was the level of WCM at which the marginal cost of adding thermal peaking generation equalled its marginal benefit in terms of reducing North Island capacity shortfall
- each standard consisted of a range of values, rather than a single value – reflecting that there was a range of scenarios over which the conditions above *approximately* hold.

The Electricity Authority (Authority) is currently reviewing the values of these standards. As part of its review, the Authority has used modelling to determine proposed new values for the standards.

The Authority has retained Concept to review the Authority's modelling – specifically, to "review the methodology and assumptions the Authority proposes to use, to help ensure they are fit for purpose".

Concept has not examined the code of the DOASA model. This was placed out of scope by the Authority.

This report sets out the findings of Concept's review. It is divided into two sections, covering the energy and capacity standards respectively.

1.1 Materials to review

The Authority has supplied Concept with the following materials:

- common to both modelling tasks:
  - a document setting out modelling assumptions
  - a slideshow setting out modelling results
- for the energy modelling task:
  - a spreadsheet of inputs to the DOASA[2] model
  - code used to prepare some of those inputs
  - inputs in CSV format, and raw model output, for a series of DOASA model runs

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[1] Consultation paper: https://www.ea.govt.nz/dmsdocument/13400
Decisions and Reasons paper: https://www.ea.govt.nz/dmsdocument/13936

[2] The DOASA model is described later in this report.

  - code to convert raw DOASA outputs to summary tables
  - those summary tables
- for the capacity modelling task:
  - a spreadsheet of inputs to the R model
  - base case inputs to the model in CSV format
  - all code used to perform the modelling
  - a spreadsheet of outputs from the R model.

The Authority has noted that code, model inputs and documentation may change after the conclusion of Concept's review.

1.2 Terminology

Energy security refers to the ability to manage the risk of shortage of fuel (in the broad sense, including water for hydro generation); *capacity* security refers to the ability to meet demand on a half-hour by half-hour basis. Energy security is typically tested in dry winters (i.e. those when hydro lakes fall to relatively low levels, driven at least in part by sustained low inflows), capacity security in winter peak demand periods when there are generation and/or transmission outages

Throughout this report, we distinguish between *standards* and *metrics*. The energy and capacity standards of 14-16%, 25.5-30% and 630-780 MW are *standards*, while NZ-WEM, SI-WEM and WCM are *metrics*. A standard is a threshold expressed in terms of a metric. For example, in a sign that says "Children must be at least 130 cm tall to use this slide", the *standard* is 130 cm, and the *metric* is measuring the child's height (in centimetres).

It is the Authority's role to define the metrics and determine the standards, and the system operator's role to evaluate the metrics for a range of future scenarios and compare them to the standards.

1.3 Focus of Concept's review

In Concept's view, the determination of each standard comprises four tasks:

1. using modelling to determine a 'threshold scenario' in which the marginal cost of adding additional firm generation (or, perhaps, some other form of capacity) is estimated to equal its marginal benefit in terms of reducing shortfall
2. choosing a metric (including defining its units and how it is to be calculated)
3. calculating a 'point estimate' of the standard (e.g. WCM = 720 MW) as the value of the metric under the threshold scenario
4. widening the point estimate into an interval (e.g. WCM = 670 – 770 MW), having regard to the range of scenarios for which the marginal cost *approximately* equals the marginal benefit, the uncertainties in the analysis, and the ways in which the power system could develop over the next few years. Sensitivity analysis is important here.

The materials supplied by the Authority to date focus on task 1 above (i.e. using modelling to determine a 'threshold scenario'). Concept understands that the Authority is still considering tasks 2-4. Task 1 is, therefore, the main focus of Concept's review.

In the course of its review, Concept has:

- commented on the suitability of the models used, with reference to the model structure and underlying assumptions

- examined the code of the R model used for the capacity analysis (without carrying out a full software audit)
- checked the explicit input assumptions used (e.g. demand, generation, etc)
- reproduced results for the central, or "base case", scenario
- reviewed the methodology for using model results to determine a 'threshold scenario'
- inspected (but not checked in detail) the sensitivity analysis carried out by the Authority.

2 The energy standard

2.1 Summary of the Authority's analysis

DOASA is a hydrothermal model of the NZ electricity system. A version of the DOASA model has been developed for the Authority by Stochastic Optimization Limited. DOASA documentation is available on the internet[3], and the Authority intends to allow the public to use the model itself at a later date.

The Authority has used DOASA to find the 'threshold scenario', by iterating over a succession of scenarios with progressively increasing amounts of generation capacity. The base case is similar to the actual power system but with a large amount of North Island thermal generation removed (resulting in substantial energy shortfall). Each successive scenario adds more firm generation (modelled as thermal) in one or both islands, until a cost-minimising point is reached.

Each scenario uses 84 hydro inflow sequences, uses average initial storage levels (as at 1 January),[4] and runs for one calendar year.

The Authority chooses a NZ-WEM metric and calculates a point estimate of the national energy standard, which is 8.5%.[5] Presumably the Authority will proceed to broaden this to an interval estimate.

The Authority then carries out various sensitivity analyses.

2.2 Suitability of the model used

DOASA is fit for purpose, in that it is a hydrothermal model with three nodes, a weekly time step and three load blocks. Concept is not aware of any errors in the DOASA formulation. Concept has not seen the DOASA code, and reviewing this code was placed out of scope.

Water valuation is the heart of a hydrothermal model, and contributes most of the complexity and run time of DOASA. Concept recommends that the Authority should keep monitoring the water values produced by DOASA, to make sure that they are reasonable.

Concept notes that:

- DOASA does not appear to model intra-week constraints on generation in much detail. In the model, both thermal and hydro generation appear to be able to cycle from high output in the top load block to low output in the bottom load block (or vice versa) relatively freely. Unit commitment is not considered.
- As currently configured, DOASA does not appear to model the cost structure of thermal generation in much detail. For each fuel (coal, gas, diesel), a single price (in $/GJ) is used at all times. In particular, DOASA does not currently reflect that the marginal cost of fuel may at times be lower than average (e.g. take-or-pay gas) or higher than average (e.g. contracting additional gas in a dry year).
- In the process of optimising the hydro release policy, DOASA uses an approximate representation of correlations between inflows from week to week.

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[3] https://www.emi.ea.govt.nz/Wholesale/Tools/Doasa

[4] In an earlier iteration of the analysis, the Authority had averaged results over a range of six initial storage levels. Concept understands, however, the Authority subsequently found that simply using average initial storage produced similar results, while delivering a large reduction in computational time.

[5] Concept understands that the Authority went on to make further changes to the definition of the WEM metric, which resulted in a numerically different (lower) value for the national energy standard.

- DOASA sometimes yields unusual behaviour in weeks 1 and 52 of the simulated year. This should not have much effect on the modelling, as only results for winter periods are used.

Concept is not aware how these issues may affect the energy standards (if at all).

2.3 Quality Assurance (QA) of the input assumptions

Generation

The Authority makes various assumptions about the generation fleet.

It is not essential that these assumptions be 100% accurate. Minor to moderate changes to the assumptions about the amount of generation and how it is operated would not have a substantial effect on the value of the energy standard, providing the assumptions used in DOASA were consistent with those used in the Authority's evaluation of the WEM metric.

Nevertheless, Concept has checked the generation assumptions and found no obvious errors.

The methodology removes much of the existing thermal fleet. Concept notes that this means there is assumed to be no existing thermal generation with a short-run marginal cost (SRMC) over $100/MWh. In contrast, the real power system includes Whirinaki, with an SRMC of very approximately $400/MWh, as well as various gas-fired peakers whose fuel costs may also be high if run at unusually high load factors during a dry winter (owing to the cost of sourcing additional gas at short notice). Additional capacity that is added back in for different scenarios has a modelled SRMC of approximately $110/MWh. This may be too high for baseload thermal generation, and too low for peaking thermal generation. Concept is unclear how this simplification may affect results.

The Authority should explain that Hawea and some Pukaki contingent storage is included, and why, and that this represents a significant change in the model of the system since the standards were last derived in 2012, and what effect this has on the standard.

Concept notes that Hawea and Pukaki contingent storage is modelled as being accessible at all times and at no additional cost. This may result in the contingent storage being used more frequently in the model than it would be in reality. Concept is unclear how this simplification may affect results, but notes that any error introduced must be less than the difference between the base case and the 'no contingent storage' sensitivity. One possible solution would be to apply a penalty to the use of contingent storage in DOASA's objective function, which would encourage the model to use normal storage before contingent storage.

Demand

The Authority models demand for generation,[6] making assumptions about demand by week, load block and node.

Concept has checked the demand assumptions and considers them broadly reasonable. The seasonality of demand, the shape of the load duration curve, and the breakdown between North Island and South Island demand are modelled appropriately. The Authority has clearly explained how transmission losses and embedded generation have been treated.

Transmission

The transmission assumptions appear broadly reasonable, although Concept cannot rule out the possibility that the analysis fails to consider some factor that limits inter-island transfer capability.

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[6] i.e. demand plus transmission and distribution losses. Throughout this report, 'demand' refers to demand for generation.

Transpower will be best placed to provide further comment on the validity of assumptions on *usable* transfer capacity from Bunnythorpe to Haywards and Haywards to Benmore under dry conditions.

Shortage costs

The energy standard is sensitive to the assumptions about shortage costs. Concept understands that the Authority plans to review its shortage cost assumptions in future. Concept recommends that, when doing so, the Authority breaks down the shortage cost curve into tranches labelled as:

- voluntary demand reductions resulting from exposure to high prices
- official conservation campaigns (if these are modelled – they may be deliberately excluded)
- rolling outages
- load shedding under grid emergency provisions.

This distinction will make it easier to assess whether the assumed shortage costs are reasonable.

Concept further recommends that:

- voluntary demand reductions and official conservation campaigns (if modelled) combined should make up no more than 10% of mass-market load (based on past experience)[7]
- even shallow rolling outages should be priced in excess of $10,000/MWh. The Authority should not assume that rolling outages would only affect low-value loads; an examination of participant rolling outage plans will show that some medium- to high-value loads would also be shed.[8]

2.4 Reproducing the Authority's results

Concept has repeated one of the Authority's DOASA runs and obtained the same results as the Authority did. This includes both the "policy" step, which determines optimal hydro release policy, and the "simulation" step, which uses the optimal hydro release policy to simulate operation of the power system.

2.5 Methodology for using model results to determine a 'threshold scenario'

The threshold scenario is the scenario minimising (shortage costs + fixed costs of added generation + operating cost of all existing thermal generation + operating costs of added generation), considered over a range of different amounts of reserve generation. This approach is analogous to finding the scenario where the marginal cost of building and operating new generation (modelled as thermal) equals the marginal benefit in terms of reducing shortage.

Concept has checked this calculation and detected no errors.

At first glance, it might be supposed that the threshold scenario should simply minimise (shortage costs + fixed costs of added generation + operating cost of added generation), leaving out the operating cost of existing thermal generation. This approach would be incorrect, however. The approach of including the full operating cost of the entire thermal fleet is correct, because it takes into account the effect of added generation on the operating costs of existing thermal generation.

Concept recommends, however, that the cost measure to be minimised should also include reductions in end-of-period hydro storage. If expended thermal fuel is costed in, then expended hydro 'fuel' (water) should also be costed in.

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[7] See paras 3.4.8-20 of https://www.ea.govt.nz/dmsdocument/8138

[8] https://www.transpower.co.nz/system-operator/security-supply/rolling-outage-plans

The Authority assumes that the fixed cost of added generation is $88/kW/year (including FOM). This is notably lower than was used in the derivation of the energy and capacity standards in 2012.

The above value is based on the capital costs and fixed operating and maintenance costs of an open cycle gas turbine (OCGT) from MBIE's "Electricity Demand and Generation Scenarios 2016" (EDGS)[9]. Assumptions about lifespan, tax rate, inflation and weighted average cost of capital (WACC) are used to convert the capital cost to an annual cost. The analysis assumes:

- the capital life expectancy (capexLife) of 30 years
- the weighted average cost of capital (WACC) of 6%.

It is Concept's view that a life expectancy of 30 years is too long for an OCGT on the margin. In Concept's experience, investors in peaking plant would typically assume a shorter economic timeframe (approx. 20 years).

Concept also considers that a WACC of 6% appears relatively low. In the Commerce Commission's latest WACC publication, the mid-point "vanilla" WACC for Transpower was estimated at 5.29% based on an asset beta of 0.34.[10] We consider investment in peaking generation to be riskier than investing in regulated monopolies, and so would expect a higher asset beta and WACC to apply. A point of comparison is material published by the Competition and Markets Authority in Great Britain – which estimated the asset beta for generation to be 0.5-0.6 and the WACC to be 7.9-9.7%.[11]

The annualised capital cost is relatively sensitive to the lifetime and WACC assumptions. For example, a lifespan of 20 years and a WACC of 8.5% would produce an annualized capital cost of $120kW/yr (including FOM). However, we note that the WEM threshold scenario is relatively insensitive to the annualized capital cost of peaking generation.

We recommend the Authority:

- carry out, and publish, sensitivities on the fixed cost of added generation
- seek feedback on its assumed capital recovery factor in the consultation process.

2.6 Draft work on the WEM metric and energy standard

The Authority proceeds to choose a NZ-WEM metric and calculate a point estimate of the national energy standard. Concept understands this work should still be treated as provisional, and has only one comment at this stage.

The metric includes a term "expected total hydro energy cleared from week 14 to 39 estimated by the market simulation over 84 inflow sequences". This term is somewhat onerous to calculate as it requires a hydrothermal model, and the result of the calculation depends on what model is used and what assumptions are made. If the Authority considered it important to have a metric that could be calculated quickly and easily (i.e. on the proverbial back of an envelope), then it should use a measure of potential hydro generation that did not require hydrothermal modelling.

Concept appreciates, however, that enabling 'back-of-an-envelope' calculation may not be a priority for the Authority.

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[9] Capital cost of $1,165/kW, fixed operating and maintenance costs of $16.4/kW/year

[10] See www.comcom.govt.nz/dmsdocument/15656

[11] See www.assets.publishing.service.gov.uk/media/54edfe9340f0b6142a000001/Cost_of_capital.pdf. The estimates for Great Britain will not be directly comparable for New Zealand because of differences in risk free rates, tax rates etc. However, the asset beta estimates are directly comparable.

2.7 Sensitivity analysis

A good range of sensitivities is provided.

As previously mentioned, the result should also be sensitised against higher/lower fixed costs of added generation. It could also be useful to test sensitivity to an increase in the probability of a dry hydro sequence.

The result of the '50% reduction in VoLL' sensitivity appeared counter-intuitive, in that it yielded a higher energy standard – we would have expected the standard would *fall* if the cost of unserved load was reduced. However, Concept understands that subsequent work, using a more sophisticated method of finding the lowest cost scenario, did in fact find a lower standard for this sensitivity.

2.8 The national energy standard has changed

The new national energy standard determined by the Authority (8.5% above expected demand)[12] is markedly different from the standard currently set out in the Code (14-16%). The reasons for the difference are not well understood – e.g. it has not been established that "the standard has fallen by X% for reason Y, despite a rise of A% for reason B". However, the difference may be due to some combination of the following factors:

- the way in which the NZ-WEM *metric* is calculated has changed
- the *input assumptions* used in the modelling have changed
- the *model* itself has changed.

As the Authority has changed all three of the above factors simultaneously, it is not clear which factor(s) are the main drivers of the change in the standard. This could be established by changing the three factors one at a time, sequentially, and observing which change had the greatest impact.

Concept appreciates, however, that the Authority is more focused on setting efficient standards for use going forwards than on making comparisons with a historical benchmark.

2.9 No South Island energy standard

Concept understands that the Authority proposes to remove the South Island energy standard, leaving only a national energy standard. Concept agrees that this appears reasonable.

The Authority has carried out modelling to demonstrate that if there *was* a South Island energy standard, it would be very implausible that the South Island WEM would fall below the standard, without the national WEM also falling below the national standard. Concept has inspected this analysis at a high level and found no errors.

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[12] Concept understands that the Authority has subsequently changed the definition of WEM, and hence the numerical value of the energy standard has fallen below 8.5%. The remarks in this section still hold.

3 The capacity standard

3.1 Summary of the Authority's analysis

The Authority has prepared a new model using the R programming language.[13] This model covers the top N winter trading periods in a year. For each trading period, it compares demand to the generation stack (considering random outages and inter-island transmission capacity) and determines the amount of capacity shortfall (if any). The model does not consider market dynamics such as unit commitment.

The Authority has used this model to find the 'threshold scenario', by iterating over a succession of scenarios with progressively increasing amounts of firm capacity. The base case has 1000 MW less capacity than the actual power system. Each successive scenario increases firm capacity in the North Island, until a cost-minimising point is reached.

The Authority chooses a WCM metric and calculates a point estimate of the capacity standard, which is 690 MW[14]. Presumably the Authority will proceed to broaden this to an interval.

The Authority then carries out various sensitivity analyses.

3.2 Suitability of the model used

The Authority's new R model is similar, but superior, to the convolution model used in the process of determining the capacity standard in 2012. The main difference is that the 2012 convolution model used Monte Carlo simulation, whereas the Authority's new model is deterministic. The deterministic approach is superior because the results do not depend on the choice of random number seed.

As such, Concept considers that the Authority's new R model is fit for purpose.

A minor issue is that the Authority's new R model covers only 500 winter trading periods per year (c.f. the modelling used in 2012 which covered the entire year). This approach misses small amounts of shortfall occurring outside the top 500 periods, as a result of multiple simultaneous generation / HVDC outages. However, the Authority's sensitivity analysis shows that this issue is not material – i.e. moving to 1000 periods would not substantially increase the standard.

A previous review of the security standards carried out in 2008 used not only an R model, but also a 'chronological model', which could model the operation of the power system over the course of an outage. The take-away from the chronological model was that some hydro schemes (Waikato, Matahina, Patea, Tokaanu) should be de-rated in the calculation of WCM, because they are unable to operate at full output for the duration of extended thermal generation and/or HVDC outages. In 2012, and again in the Authority's current review of the security standards, this finding was incorporated into the R modelling. Accordingly, further chronological modelling is not needed.

3.3 QA of the model code

Concept has:

- checked the R code on a line-by-line basis
- traced selected key parameters from input assumptions, to intermediate workings, to output quantities.

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[13] R is a general-purpose programming language, often used for statistical analysis – see https://www.r-project.org/

[14] Concept understands that the Authority went on to make further changes to the definition of the WCM metric, which resulted in a numerically different (lower) value for the capacity standard.

No errors were detected.

Caveat: this QA does not represent a full software audit.

3.4 QA of the input assumptions

Generation

The Authority makes various assumptions about generation capacity, which are split between the input data files and the R code.

It is not essential that these assumptions be 100% accurate. Minor to moderate changes to the generation assumptions would not have a substantial effect on the value of the capacity standard, providing the assumptions used in the R model were consistent with those used in the Authority's evaluation of the WCM metric.

Nevertheless, Concept has checked the generation assumptions and found no obvious errors.

The convolution approach assumes all different *types* of uncontrollable generation[15] are independent from each other, while generation of the same type is correlated according to historical output. This approach may not pick up some correlation between different types of generation, and Concept suggests investigating this further with a sensitivity where all uncontrollable generation combined is modelled according to historical output.

The R model applies a 60 MW derating to the maximum output of the Waikato system, reflecting that the scheme may not be able to continue operating at maximum output for the duration of an extended generation outage. However, the R model assumes that the Lower Waitaki and Clutha schemes can deliver maximum output whenever needed, subject only to a 2% forced outage rate applied to each unit. Concept considers these assumptions are broadly reasonable.

Demand

The Authority makes assumptions about demand for generation in the top 500 trading periods per year.

As with generation, it is not essential that these assumptions be 100% accurate. (The Authority's sensitivity analysis shows that an upward or downward shift in assumed demand does not have a substantial effect on the value of the standard.)

Nevertheless, Concept has checked the demand assumptions and considers them broadly reasonable. The shape of the load duration curve, and the correlation between North Island and South Island demand, are modelled appropriately. The Authority has clearly explained how transmission losses and embedded generation have been treated.

Inter-island transmission

The inter-island transmission assumptions appear broadly reasonable. Transpower will be best placed to provide further comment on the validity of assumptions on (usable) HVDC capacity, losses, and monopole and bipole outage rates.

Ancillary services

Assumptions on instantaneous reserve (IR) requirements and interruptible load availability appear broadly reasonable.

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[15] 'Uncontrollable generation' includes wind generation, run of river hydro, geothermal, co-generation plant and miscellaneous 'small stations'

Frequency keeping does not appear to be modelled – the Authority should briefly set out the reason for this omission.

Shortage costs

The capacity standard is sensitive to the assumptions about shortage costs. Concept understands that the Authority plans to review its shortage cost assumptions in future. Concept recommends that, when doing so, the Authority breaks down the shortage cost curve into tranches labelled as:

- voluntary energy demand response
- involuntary energy curtailment
- potentially, IR shortfall (having regard to the amount of IR shortfall that can be permitted when there is a high level of northwards HVDC transfer).

This distinction will make it easier to assess whether the assumed shortage costs are reasonable.

Published studies of the value of lost load (VoLL) may be informative about the cost structure of the second tranche above (involuntary energy curtailment). This tranche could be split into several sub-tranches of increasing marginal cost.

3.5 Reproducing the Authority's results

Concept has rerun the R model and successfully reproduced the Authority's base case results.

3.6 Methodology for using model results to determine a 'threshold scenario'

The Authority determines the threshold scenario as the scenario minimising (shortage costs + fixed cost of added generation + variable cost of added generation in periods where there is shortfall), considered over a range of different amounts of added generation. This approach is analogous to finding the scenario where the marginal cost of adding new generation equals its marginal benefit in terms of reducing shortage (as per Section 1).

Concept has checked this calculation and detected no errors.

The Authority assumes that the fixed cost of added generation is $144/kW/year. This is a different value from that used in the energy modelling, because it is based on a different type of generation (reciprocating diesel units). Concept agrees that it is appropriate to use different cost assumptions for the two analyses, given that dry-year reserve capacity could operate rather differently from peaking capacity.

The capacity standard is sensitive to the assumed fixed cost of added generation. Concept considers that this assumption, based on the cost of a reciprocating diesel unit, is broadly appropriate for this purpose. Notwithstanding this, Concept's comments on capital recovery factors in Section 2.5 also apply here.

3.7 Draft work on the WCM metric and capacity standard

The Authority proceeds to choose a WCM metric and calculate a point estimate of the capacity standard. Concept understands this work should still be treated as provisional, and has only two comments at this stage:

- the Authority should consider what capacity factor to use for new wind in the WCM metric (in other words, how much perfectly reliable thermal peaking generation would be needed to provide the same capacity benefit as 100 MW of new wind generation?)
- the calculation of HVDC contribution in the WCM metric is a little onerous, as it requires convolving South Island net supply with HVDC outages. It cannot be carried out 'on the back

of an envelope'. Concept appreciates, however, that enabling 'back-of-an-envelope' calculation may not be a priority for the Authority.

3.8 Sensitivity analysis

A good range of sensitivities is provided.

VoLL could perhaps be varied by more than +/-10%. The sensitivities titled '10pct_DC_outage', '5pct_DC_outage' and 'Wind_only' seem unrealistic and could perhaps be omitted.

The result of the '840 MW HVDC limit' scenario (a *decrease* in the capacity standard) may be counter-intuitive to some readers, who might reason that a lower HVDC limit would reduce North Island capacity security, resulting in a higher security standard being required. We consider, however, that it makes sense upon reflection – given that a change to the HVDC limit acts to reduce the WCM *metric* as well as the *standard*. This sensitivity would benefit from further explanation.

Some sensitivities seem to be affected by a small 'random' error of up to about 10 MW. We understand this is a result of discretisation in the method.

3.9 The capacity standard has not changed much in numerical terms

The new capacity standard determined by the Authority (690 MW)[16] falls within the standard currently set out in the Code (630-780 MW). Nonetheless, the level of generation surplus represented by the standard may have changed, because the new WCM metric is different from the status quo WCM metric. The difference between the two metrics is not fundamental – both are measures of WCM, both are driven by the gap between winter peak supply and demand in MW terms – but nevertheless the two metrics are calculated in different ways and therefore take different values.[17]

If the Authority wanted to establish whether the meaning of the standard had changed, it could be helpful to calculate what the value of the new standard would have been if the status quo WCM metric had been retained.

Concept appreciates, however, that the Authority is more focused on setting efficient standards for use going forwards than on making comparisons with a historical benchmark.

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[16] Concept understands that the Authority has subsequently changed the definition of WCM, and hence the numerical value of the capacity standard has fallen below 690 MW. The remarks in this section still hold.

[17] For instance, the new metric assigns a higher value to existing wind generation than the status quo metric.