Meeting Date: 27 May 2021

FIT-FOR-PURPOSE REVIEW: CONTROLLING THE RISK OF SUPPLY EMERGENCIES USING SECURITY OF SUPPLY FORECASTING AND OFFICIAL CONSERVATION CAMPAIGNS

SECURITY AND RELIABILITY COUNCIL

This paper summarises the current regulatory arrangements relating to security of supply forecasting and Official Conservation Campaigns (OCCs) and assesses whether current regulatory arrangements provide effective controls on the risk of supply emergencies.

Note: This paper has been prepared for the purpose of enabling the Security and Reliability Council to formulate advice to the Authority on whether regulatory arrangements relating to security of supply forecasting and OCCs provide effective controls on the risk of energy- or capacity-based supply emergencies. Content should not be interpreted as representing the views or policy of the Electricity Authority.

Contents

1 Review of whether regulatory arrangements for security of supply forecasting and official conservation campaigns provide effective controls on the risk of supply emergencies

1.1.1 The Security and Reliability Council's (SRC) functions under the Electricity Industry Act 2010 (Act) include providing advice to the Electricity Authority (Authority) on:

a) the performance of the electricity system and the system operator, and

b) reliability of supply issues.

1.1.2 In pursuit of its purpose, the SRC developed a risk management framework to identify key arrangements for managing risks to reliability of supply. The framework identified the regulatory arrangements for security of supply forecasting and official conservation campaigns (OCCs) as warranting the SRC's attention periodically.

1.1.3 The purpose of this paper is to enable the SRC to formulate advice to the Authority on whether regulatory arrangements relating to security of supply forecasting and OCCs provide effective controls on the risk of energy- or capacity-based supply emergencies.

1.1.4 To inform that advice, the paper:

a) summarises the current regulatory arrangements relating to security of supply forecasting and OCCs

b) assesses whether current regulatory arrangements provide effective controls on the risk of supply emergencies.

1.1.5 This paper is not intended to describe or address the current security of supply situation.

2 Regulatory arrangements for security of supply forecasting and Official Conservations Campaigns

2.1.1 This section describes the current regulatory arrangements for forecasting security of supply and using OCCs to manage supply emergencies.

2.2 The Act places obligations on the Authority and the system operator

2.2.1 The Act places obligations on both the Authority and the system operator in relation to security of supply.

2.2.2 The Act defines the Authority's statutory objective as "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".[1] The Authority interprets its objective of 'promoting reliable supply by the electricity industry for the long-term benefit of consumers' as meaning:

[1] Section 15.

Exercising its functions in ways that encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events.[2]

2.2.3 The primary way in which the Authority does this is through the development and enforcement of Code provisions. The Code contains a mixture of market-based and administrative mechanisms that contribute to the reliable supply of electricity.

2.2.4 In relation to security of supply forecasting and the management of supply emergencies using OCCs, the Authority's role is to specify, via the Code, the system operator's functions and how they are to be performed.

2.2.5 This is because the Act specifically requires:

a) that the system operator must:

  i. provide information, and short- to medium-term forecasting on all aspects of security of supply

  ii. manage supply emergencies[3]

b) that the Code must:

  i. specify the functions of the system operator

  ii. specify how the system operator's functions are to be performed

  iii. set requirements relating to transparency and performance.[4]

2.2.6 To this end, Parts 7, 8 and 9 of the Code set out the system operator's functions in relation to security of supply and managing supply emergencies, and how the system operator is to perform those functions.

2.2.7 Of relevance to this paper are:

a) arrangements in Part 7 relating to the provision of information, and short- to medium-term forecasting on security of supply

b) arrangements in Part 9 relating to the use of OCCs to manage supply emergencies.

2.3 Providing information and short- to medium-term forecasting on security of supply

Security of supply forecasting and information policy

2.3.1 Part 7 of the Code says the system operator needs to prepare and publish a security of supply forecasting and information policy (SOSFIP),[5] which must require the system operator to:

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2 Electricity Authority, 14 February 2011, Interpretation of the Authority's statutory objective, p. 8.

3 Section 8.

4 *Ibid*

5 Clause 7.3(1).

a) prepare and publish at least annually, a security of supply assessment (SoSAA[6]) containing detailed supply and demand forecasts for at least five years, which assists interested parties to assess whether the security of supply standards for energy and capacity set out in Part 7 of the Code are likely to be met

b) 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

c) publish, in relation to the above information, sufficient details of the modelling data, assumptions, and methodologies the system operator has used to allow interested parties to recreate that information (but without publishing information which is confidential to any participant).

2.3.2 The SOSFIP is intended to give effect to the Act's requirement that the system operator provide information, and short- to medium-term forecasting on all aspects of security of supply. This information helps industry participants manage security of supply risks. The SOSFIP says the system operator's principal objective under the SOSFIP is to ensure, to the extent possible, that high-quality information related to security of supply is provided to all interested parties.[7]

2.3.3 The system operator prepares the SOSFIP, while the Authority approves it. The SOSFIP is incorporated by reference in the Code.

Information and short-term forecasting on security of supply

2.3.4 In accordance with the SOSFIP, the system operator publishes a weekly security of supply report. This must include:

a) a comparison of total storage in key hydro lakes[8] with the electricity risk curves (ERCs), which show the quantified level of risk of future electricity supply shortage at different hydro storage levels in the South Island and New Zealand

b) the electricity risk meter status

c) other information including (but not limited to) hydro inflows, generation at key thermal generating stations, demand, inter-island electricity transfers, and contingent hydro storage[9] currently available for generation.[10]

Electricity Risk Curves

2.3.5 Electricity Risk Curves (ERCs) (illustrated in Figure 1 and Figure 2) are the primary instrument for monitoring the sufficiency of all fuels for electricity generation, though

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6 'Security of supply annual assessment'.

7 Security of Supply Forecasting and Information Policy, 15 December 2020, p.1.

8 Lakes Tekapo, Pukaki, Hawea, Te Anau and Manapouri for South Island hydro storage, with the addition of Lake Taupo for New Zealand hydro storage.

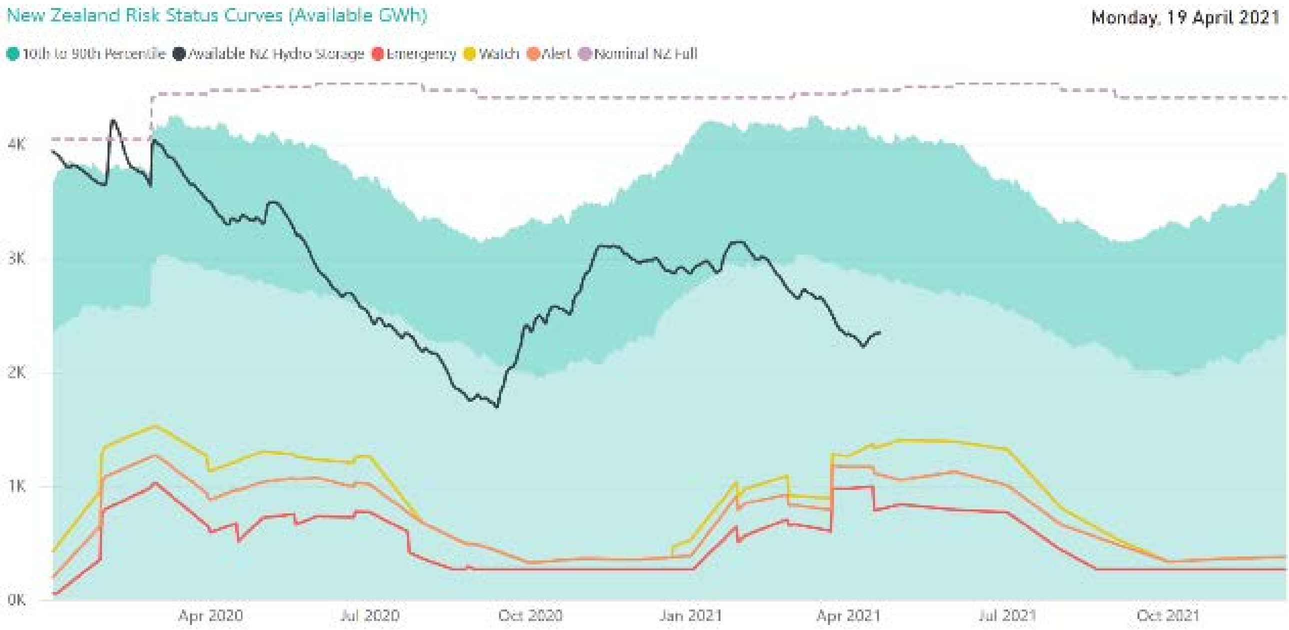
9 This is additional hydro storage that becomes available for generation when the risk of future electricity shortage reaches a certain quantified level (represented by a particular ERC).

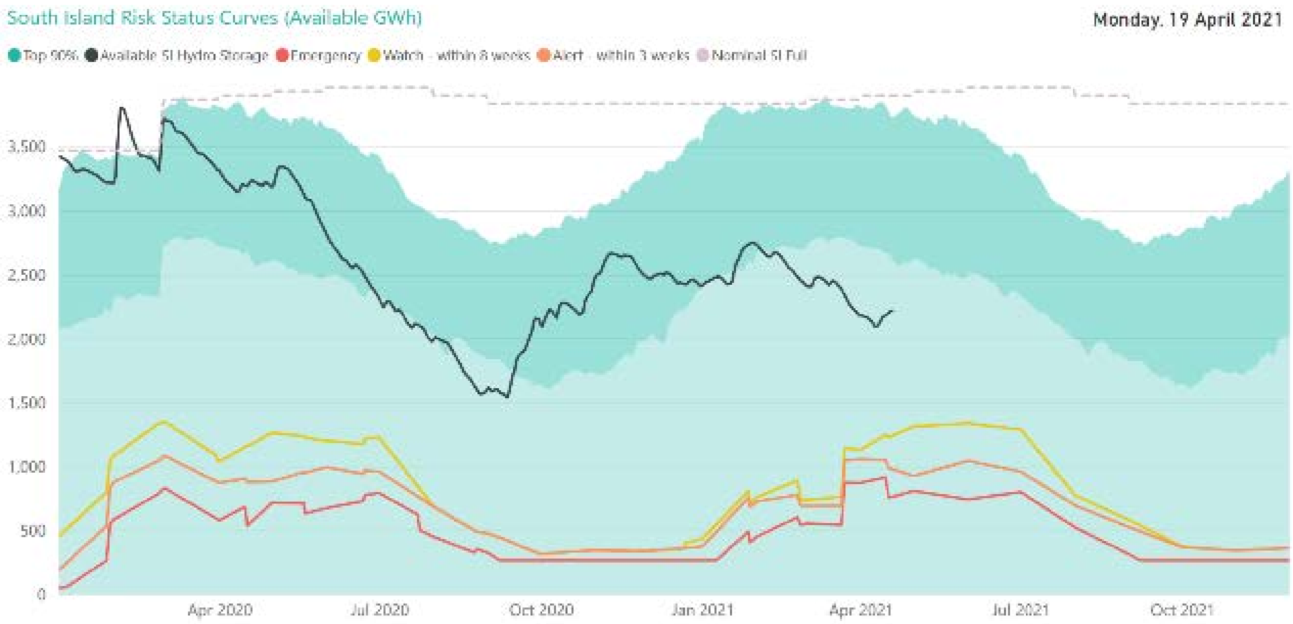
10 Security of Supply Forecasting and Information Policy, 15 December 2020, pp. 6–7.

the risk is presented in terms of the energy of stored water (being the single most variable and critical fuel in New Zealand's generation fleet).

Figure 1: Comparison of storage with electricity risk status curves[11]

The graphs below compare New Zealand and South Island controlled storage to the relevant electricity risk status curves.

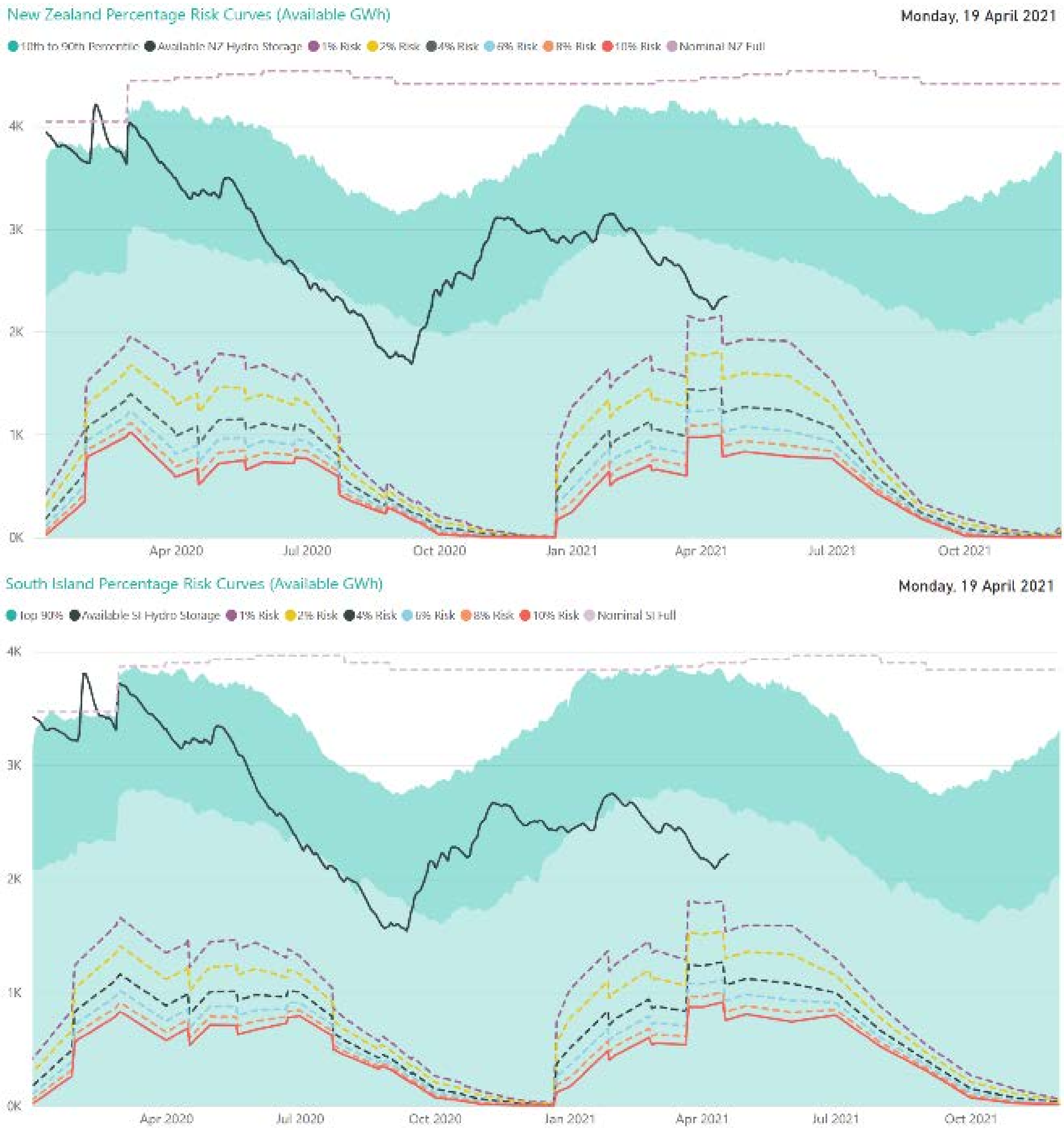




11 Refer to https://www.transpower.co.nz/system-operator/security-supply/electricity-risk-curves.

Figure 2: Comparison of storage with electricity risk curves – percentage risk[12]

The graphs below compare New Zealand and South Island controlled storage to the relevant electricity risk curves – percentage risk (being 1%, 2%, 4%, 6%, 8%, and 10% risk)



2.3.6 ERCs come in two types: risk *percentage* curves and risk *status* curves. ERCs are produced for the South Island and for New Zealand.

12 Refer to https://www.transpower.co.nz/system-operator/security-supply/electricity-risk-curves.

2.3.7 Each risk percentage curve represents a probability that total storage available for hydro generation[13] will, despite generation behaviour modelled to minimise the use of hydro generation, fall to zero in the following 12 months, based on the distribution of historical inflow sequences. For example, at the 10% risk percentage curve, total storage would fall to zero in 10% of historical inflow sequences dating back to 1931.

2.3.8 There are three risk status curves: 'Watch', 'Alert' and 'Emergency':

a) the Watch curve represents the point at which an OCC would be required within eight weeks, given poor (but not 'worst case') inflows

b) the Alert curve is the same as the Watch curve, but with three weeks to an OCC

c) the Emergency curve represents the point at which the Authority considers there to be an unacceptable risk to consumers of rolling outages occurring in the absence of regulatory intervention in the form of an OCC. The Emergency curve is usually equal to the 10% risk percentage curve, but also has some floors applied to ensure operability at low hydro lake levels.

2.3.9 In determining the ERCs, the system operator must use various inputs and assumptions—for example:

a) the system operator should assume short-term market behaviour that seeks to minimise use of hydro storage[14]

b) unless reasonably reliable information known to the system operator indicates otherwise, the system operator should assume full availability of installed transmission and generation assets and no constraints on the availability of thermal fuel.[15]

2.3.10 The inputs and assumptions used in determining the ERCs are on the system operator's website, alongside the methodology used to determine the ERCs.[16] Changes to these inputs and assumptions may result in changes to the ERCs (eg, a major unplanned thermal generation outage will raise the ERCs).

2.3.11 The system operator must review and, if necessary, update the inputs and assumptions used in the ERCs at least once a (calendar) month, and more frequently if:

a) the system operator becomes aware of new reasonably reliable information that the system operator considers may yield a material change to the ERCs, or

b) the system operator considers a change to an electricity risk meter status from 'Alert' to 'Emergency' is imminent.[17]

13 The volume of water stored in hydro lakes is expressed as energy available to produce electricity (in GWh).

14 Please note, the assumption that thermal generation will run as required to conserve hydro storage is made for the purpose of developing an ERC, rather than representing a genuine view that the market will deliver this outcome.

15 Security of Supply Forecasting and Information Policy, 15 December 2020, pp. 3–4.

16 https://www.transpower.co.nz/system-operator/security-supply/electricity-risk-curves and https://www.transpower.co.nz/system-operator/security-supply/hydro-risk-curves-explanation.

17 Security of Supply Forecasting and Information Policy, 15 December 2020, p. 4.

The electricity risk meter

2.3.12 The electricity risk meter (illustrated in Figure 3) shows the forecast time to an OCC based on the rate of decline in available hydro storage:

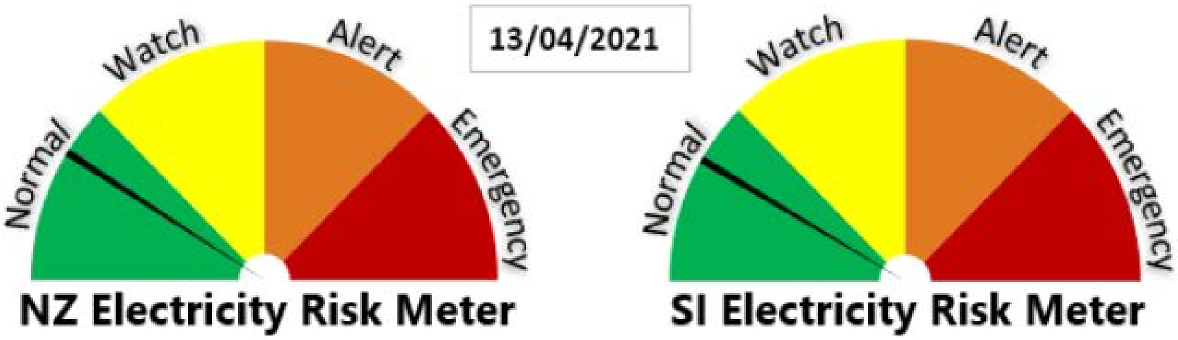
a) a status of 'Normal' indicates actual hydro storage is above the Watch risk status curve

b) a status of 'Watch' indicates actual hydro storage is below the Watch risk status curve but above the Alert risk status curve

c) a status of 'Alert' indicates actual hydro storage is below the Watch risk status curve but an OCC has not been declared

d) a status of 'Emergency' means the system operator has started an OCC, which would typically be because actual hydro storage has fallen below the Emergency risk status curve.[18]

Figure 3: Electricity risk meter



Information and medium-term forecasting on security of supply

2.3.13 In accordance with the SOSFIP, the system operator publishes a SoSAA annually. The SoSAA is the system operator's medium-term assessment of security of supply. It provides a 10-year view of energy and capacity adequacy in the New Zealand electricity system, under demand and supply scenarios covering a range of futures that the system operator considers plausible.[19]

2.3.14 As noted earlier, the SoSAA is intended to assist interested parties to assess whether the energy security of supply standard and the capacity security of supply standard are likely to be met. The Code specifies that:

a) the energy security of supply standard is a winter energy margin of 14–16% for New Zealand and a winter energy margin of 25.5–30% for the South Island

b) the capacity security of supply standard is a winter capacity margin of 630–780 MW for the North Island.[20]

2.3.15 These three margins have been calculated to represent an efficient level of reliability—that is, a level of reliability that minimises the expected combined cost of an energy/capacity shortfall and the provision of reserve energy/capacity.

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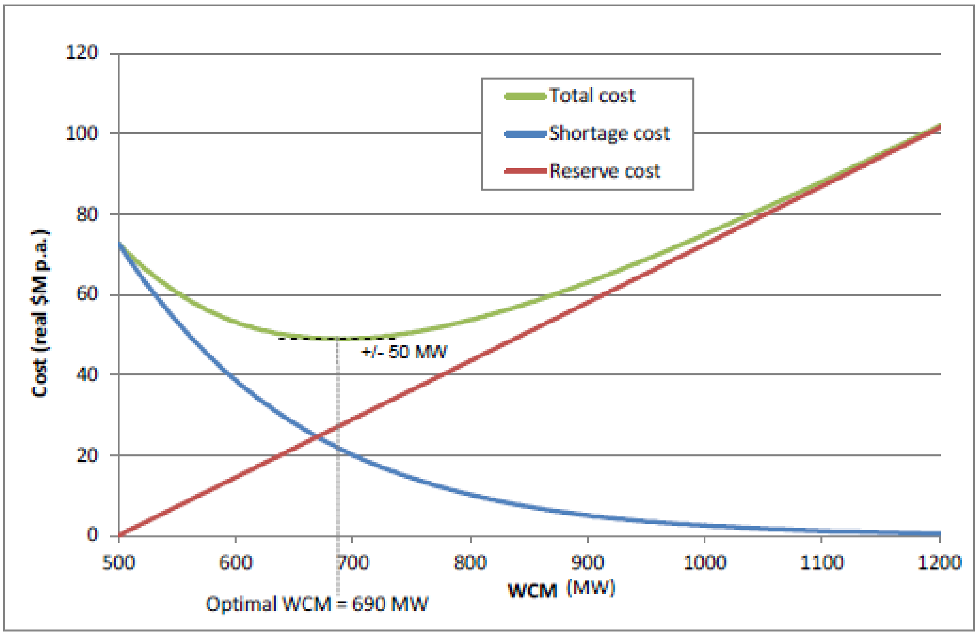
18 Security of Supply Forecasting and Information Policy, 15 December 2020, p. 5.

19 Transpower New Zealand, Security of Supply Annual Assessment 2020, p. 4.

20 Clause 7.3(2).

2.3.16 Figure 4 shows the trade-off between the costs of a shortfall in capacity and the costs of reserve (generation) capacity. The optimal capacity margin is that which achieves the minimum combined cost of reserve capacity and expected unserved energy (lost load)—ie, the lowest point on the green curve.

Figure 4: Trade-off between costs of capacity shortfall and reserve capacity[21]



2.3.17 The calculation of the two energy margins and the one capacity margin considered, amongst other things:

a) the availability of existing generation

b) predicted new generation

c) the cost of reserve generation capacity

d) demand growth

e) the cost of capacity/energy shortage—for different types of demand reduction (eg, price-responsive demand, instantaneous reserves shortfall, voluntary conservation, rolling outages)

f) thermal generation fuel costs

g) thermal generation outages

h) transmission constraints and outages

i) hydro storage

j) uncertainty in demand, base load generation, wind generation, availability of thermal generation, hydro inflows, and hydro storage at the start of winter.[22]

2.3.18 An important advantage of the winter energy margin and winter capacity margin metrics is that they provide relatively simple and understandable measures of the

21 Electricity Authority, 2012, Winter Energy and Capacity Security of Supply Standards – Consultation paper, p. 17.

22 Electricity Authority, 2012, Winter Energy and Capacity Security of Supply Standards – Consultation paper.

ability of the electricity system to manage two key sources of medium-term security of supply risk:

a) the New Zealand and South Island winter energy margins assess whether it is likely there will be an adequate level of generation and HVDC transmission capacity to meet *expected electricity demand across the winter months*, and

b) the North Island winter capacity margin assesses whether it is likely there will be adequate generation and HVDC transmission capacity to meet *expected North Island peak winter demand*.[23]

Figure 5: New Zealand winter energy margin for all scenarios[24]

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

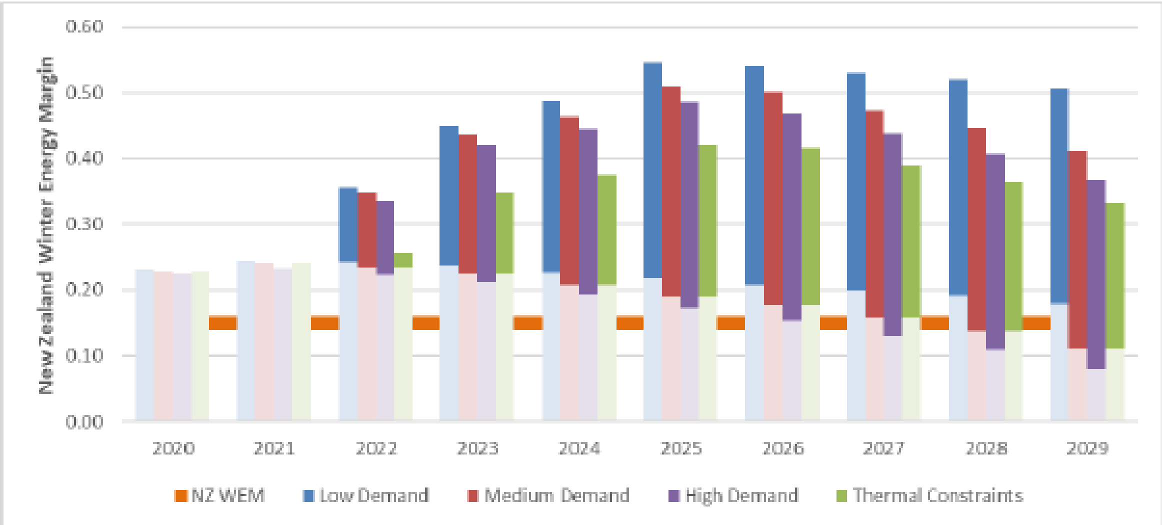


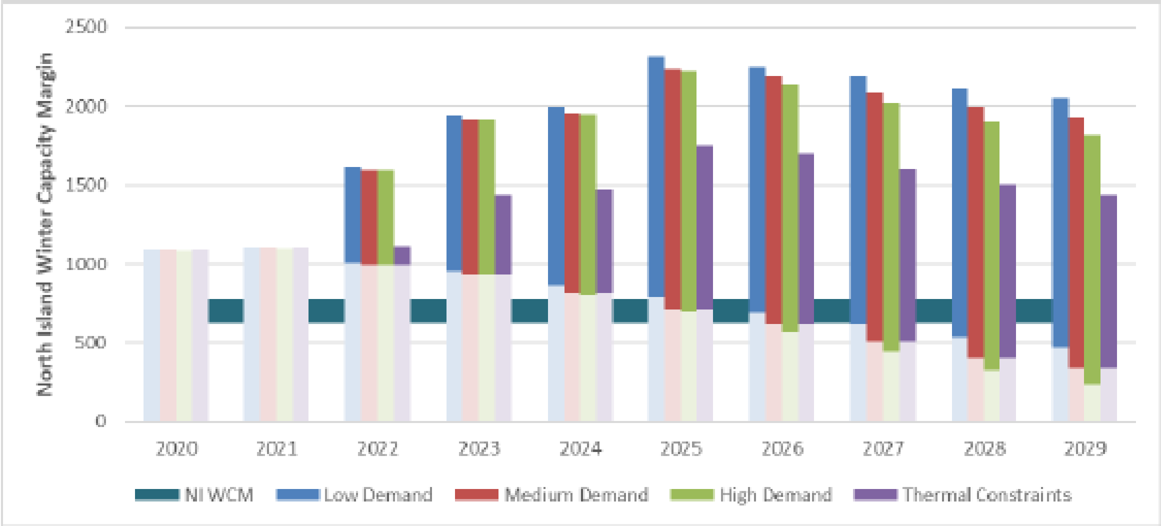
Figure 6: North Island winter capacity margin for all scenarios[25]

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

23 There is no South Island winter capacity margin because of generation capacity exceeding peak electricity demand.

24 Transpower New Zealand, Security of Supply Annual Assessment 2020, p. 6.

25 *Ibid*



2.3.19 Figure 5 and Figure 6 reproduce the New Zealand winter energy margin and the North Island winter capacity margin contained in the 2020 SoSAA. To maintain the New Zealand winter energy margin, new generation will be required by 2026–2027 for the ‘medium demand’ and ‘high demand’ scenarios. To maintain the North Island winter capacity margin, investment in new generation will be required by 2025–2026 in all four scenarios modelled by the system operator.

2.4 Managing supply emergencies using Official Conservation Campaigns

2.4.1 The Code contains several arrangements that are intended to give effect to the Act’s requirement for the system operator to manage supply emergencies. This paper’s focus is on the regulatory arrangements relating to OCCs. OCCs are intended to assist in avoiding, or at least mitigating, forced energy shortages.

2.4.2 Appendix A summarises other regulatory arrangements for managing supply emergencies, to put into context the OCC arrangements.

The regulatory arrangements for Official Conservations Campaigns

2.4.3 The overwhelming majority of mass-market consumers are not exposed to electricity spot prices. Hence, they see no price signal to reduce their electricity use as the risk of an energy shortage increases. OCCs are intended to reduce aggregate energy consumption during periods of low hydro inflows, until rain or snow melt replenishes the hydro lakes, or until high winter demand passes.[26]

2.4.4 An OCC is a campaign to encourage electricity conservation, which the system operator starts and ends. An OCC can cover either the South Island or all New Zealand and could (without regulatory intervention) alternate between the two states.[27]

2.4.5 The Code requires the system operator to start an OCC:

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26 Electricity Authority, 18 October 2016, The security of supply framework – Information paper, p. 7.

27 Clause 1.1(1), clause 9.23, and clause 9.23A.

a) when the risk of electricity shortage for the South Island or New Zealand is at least 10% and is forecast to be at least 10% for a week or more, or

b) when storage in the South Island or New Zealand hydro lakes is, and is forecast to remain so for a week or more, equal to or less than—

i. that storage which can only be used during an OCC, plus

ii. 50 GWh (unless the system operator determines and makes publicly available one or more different quantities for the hydro lakes), or

a) if it has agreed a date with the Authority for an OCC to start, on that date.[28]

2.4.6 The system operator must use reasonable endeavours to give the Authority and each industry participant at least two weeks' notice of an OCC starting.[29]

2.4.7 The Code requires the system operator to end an OCC:

a) when the risk of electricity shortage for the South Island or New Zealand is less than 8%, or

b) when storage in the South Island or New Zealand hydro lakes is greater than—

i. that storage which can only be used during an OCC, plus

ii. 50 GWh (unless the system operator determines and makes publicly available one or more different quantities for the hydro lakes), or

c) if it has agreed a date with the Authority for an OCC to end, on that date.[30]

2.4.8 An OCC triggers the obligation on retailers to compensate qualifying consumers in the South Island or across New Zealand (as the case may be) a minimum of $10.50 a week. This obligation remains in place until the OCC ends.

3 Do regulatory arrangements for security of supply forecasting and Official Conservation Campaigns provide effective controls on the risk of supply emergencies?

3.1 Overview

3.1.1 This section:

a) identifies risks that could result in supply emergencies

b) assesses whether current regulatory arrangements for security of supply forecasting and OCCs provide effective controls on the risk of supply emergencies.

3.1.2 Generally speaking, the current regulatory arrangements for security of supply forecasting and OCCs appear to be fit-for-purpose in the provision of effective

28 Clause 9.23.
29 *Ibid*
30 *Ibid*

controls on the risk of supply emergencies. However, given the expected changes to the New Zealand electricity industry over the coming 10–15 years, it would appear prudent to reassess these arrangements in 2–4 years' time.

Table 1: The Authority's initial evaluation of whether regulatory arrangements for security of supply forecasting and OCCs are effective in managing the risk of supply emergencies

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
	Regulatory arrangements for security of supply forecasting				
1	The energy and capacity security of supply standards may be materially incorrect.	The security of supply standards may be materially too low. This could result in the under-build of generation, should the annual SoSAA be used as a key information input to generation investment decisions.	**Impact threshold met** The under-build of generation would have a material adverse impact on security of supply and cause significant economic loss.	**Low likelihood of risk becoming an issue** The Authority undertook a partial review of the security of supply standards in 2017–2018. This showed limited benefit from changing the security of supply standards, because of the minor effects from changing the standards.	**Effectiveness of regulatory arrangements may be improved** The 2017–2018 review of security of supply standards identified one likely regulatory change: The South Island winter energy margin was found to be analytically worthless due to improvements in HVDC link capacity. Therefore, it should be removed. The 2017–2018 review also mooted shifting responsibility for calculation of winter security margins from the Authority to the system operator and having these standards recalculated regularly in a more dynamic way. Given the transition to a low-carbon economy,

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
					reviewing the security of supply standards would seem desirable. Therefore, the secretariat suggests the SRC advise the Authority to commit to a timeframe for completing the next review of the standards.[31]
2	Information on gas supply arrangements may be incomplete.	The system operator's information on gas supply arrangements is not as fulsome as it could be, which adversely affects the accuracy of the system operator's security of supply information and short- to medium-term forecasting. This could result in industry participants making demand/supply decisions (eg, scheduling of plant maintenance) that contribute to or exacerbate supply emergencies.	**Impact threshold met** The under-provision of available generation capacity could have a material adverse impact on security of supply and cause significant economic loss.	**Medium likelihood of risk becoming an issue** The exchange of timely and accurate information on gas supply arrangements between relevant gas and electricity industry participants and the system operator is currently an informal process. This raises the possibility that changes in processes, procedures, and personnel could result in less effective information transfer. It also risks a lack of accountability if (what	**Effectiveness of regulatory arrangements could be improved** The secretariat understands the system operator considers the informal approach to exchanging information on gas supply arrangements provides valuable opportunities for exchanging information that a more formal process may inhibit. However, it would appear prudent for the Authority to review whether there are potential options to

[31] Refer to https://www.ea.govt.nz/development/work-programme/risk-management/winter-energy-and-capacity-margins-review-20172018/development/.

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
				turns out to be) critical information is not exchanged between relevant gas industry participants, electricity industry participants, and the system operator. As New Zealand's spare gas capacity falls, the criticality of timely and accurate information on gas supply arrangements is expected to increase.	improve on the current informal approach. The secretariat suggests the SRC advise the Authority to include this review in its current work on wholesale market information disclosure.
	Regulatory arrangements for OCCs				
3	The ability of the power system to operate with low and uneven hydro lake levels is not well understood.	The ERC approach effectively treats the controlled hydro lakes (Tekapo, Pukaki, Hawea, Te Anau, Manapouri, and Taupo for national analysis) as a single large reservoir. "Shortage" is interpreted as the point where the super-reservoir runs out of water (or would run out of water, if not for rolling outages). In practice, a severe supply emergency would likely	**Impact threshold met** An inability to access storage in key hydro lakes because of uneven draw down of hydro storage would have a material adverse impact on security of supply and cause significant economic loss if it led to rolling outages.	**Low likelihood of risk becoming an issue** The expectation is that OCCs will occur infrequently, meaning the risk of key hydro lakes being drawn down to low levels will occur very infrequently. Defining "infrequently" is not straightforward. The cost-benefit analysis (CBA) supporting the Authority's decision to implement the	**Regulatory arrangements appear effective** The risk is more with the inputs and assumptions used in determining the ERCs, rather than the regulatory arrangements within which the ERCs sit. The best way to resolve the issue may be for Transpower to carry out analysis to better understand how the power system may operate with

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
		result in some hydro lakes running low on water before others. The possible consequences are not well understood. For instance, there could be capacity shortages before total hydro lake storage was exhausted. Therefore, the ERCs may overstate the ability of the power system to operate using water from key hydro lakes with reasonable storage when one or more other key hydro lakes are drawn down to a very low level. If so, appropriate mitigating steps, such as		customer compensation scheme (CCS) arrangements in 2011 assumed the frequency of OCCs would change from a baseline scenario of once in five years[32] to between once in eight years and once in 10 years.[33] It has now been 10 years since the Authority put in place the CCS and OCC regulatory arrangements. During this time there have been two years with very low hydro inflows—across New Zealand in 2012, and in the South Island in 2017.[34] In both instances OCCs were not needed.	low and uneven hydro lake levels, and to communicate the results to interested parties. The Authority may have some role in instigating this work.

32 The CBA noted that OCCs had occurred around every three years, on average, during the 2000s. However, the CBA's baseline scenario assumed this frequency would drop to once in five years because the following actions would promote improved management of hydro resources and higher investment in generation capacity for peak demand:

- restructuring of state-owned enterprise generator-retailers through physical and virtual asset transfers,
- phasing out of the Reserve Energy Scheme, and
- sale of the Whirinaki reserve generation plant (which had suppressed prices, so deterred investment in peaker plants).

33 Electricity Commission, 13 August 2010, An integrated cost-benefit analysis of the market development programme, p. 23.

34 See, for example:

- Electricity Authority, October 2017, Briefing to the Incoming Minister, p. 16.
- Electricity Authority, 22 March 2018, 2017 Winter review – Final report, p. 3.

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
		an OCC, may not occur early enough.		This indicates that OCCs may be needed less frequently than originally expected—perhaps only a handful of times over a century.	
4	An OCC may end too soon because the trigger for ending an OCC is inappropriate.	From September to December the triggers for starting and ending OCCs are very close together. An OCC during this period could end shortly after it began if hydro storage quickly rebounded from the 10% ERC to the 8% ERC. But another OCC could start soon thereafter (ie, after less than a week), if hydro storage fell to the 10% ERC again. Such ‘flip-flopping’ behaviour would undermine conservation efforts.	**Impact threshold met** Low energy savings levels could have a material adverse impact on security of supply and cause significant economic loss.	**Low likelihood of risk becoming an issue** OCCs between September and December are expected very infrequently, meaning this risk would have a very low probability of occurring.	**Regulatory arrangements appear effective** The Authority looked at this issue in 2018–2019 and made a minor change to the regulatory arrangements. Submitters on the Authority’s Code amendment proposal suggested alternatives to both the Authority’s proposal and the Authority’s final decision. It may be prudent to revisit this risk within five years, as part of a periodic general review of the regulatory arrangements for using OCCs to manage supply emergencies. The system operator and Authority can agree alternative dates to start and stop OCCs, so could

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
					intervene to mitigate the impact of this risk.
5	The Code provisions for sub-national OCCs may not be appropriate.	Negative consumer perception of a South Island-only OCC could undermine its perceived legitimacy, weaken its effectiveness, damage long-term confidence in the electricity industry and affect the durability of the OCC and CCS arrangements. Running a South Island-only campaign could also undermine energy conservation efforts by creating additional complexity, particularly if it segued into a national campaign or vice versa.	**Impact threshold met** Low energy savings levels could have a material adverse impact on security of supply and cause significant economic loss.	**Low likelihood of risk becoming an issue** OCCs are expected infrequently.	**Effectiveness of regulatory arrangements may be improved** When clause 9.23 of the Code was drafted in 2011, relatively limited southward transfer capacity existed on the HVDC link. Changes in the physical power system since 2011 have improved the ability to transfer energy from the North Island to the South Island. In 2018–2019 the Authority sought feedback on removing South Island-only OCCs—first, as part of a consultation on other changes to the regulatory arrangements for OCCs, and then via a survey. While most survey respondents supported the removal of South Island-only OCCs, the Authority was not satisfied they were adequately representative of the parties affected by

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
					the proposed change. The Authority therefore could not be satisfied there was widespread support to amend the Code using section 39(3)(b) of the Act. The Authority's preliminary analysis suggests the overall net benefit from removing South Island-only OCCs is unlikely to be very significant, given the infrequency of these. There may be an opportunity to include this change as part of one of the Authority's omnibus Code amendment proposals. The system operator and Authority can agree alternative dates to start and stop OCCs, so could intervene to mitigate the impact of this risk.
6	Retailers may not have a sufficiently strong incentive to avoid rolling outages.	The CCS creates a strong incentive for retailers to act to avoid OCCs. However, there is no compensation requirement on retailers in the event of rolling outages	**Impact threshold met** Reaching rolling outages sooner would have a material adverse impact on security of supply and	**Low likelihood of risk becoming an issue** Retailers would be expected to be very reluctant to take steps that would materially increase	**Regulatory arrangements appear effective** The system operator decides on the length of an OCC independent of

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
		due to an energy shortage. Retailers may therefore have an incentive to hasten rolling outages if an OCC has already begun.	cause significant economic loss.	the likelihood of rolling outages. Reasons for this include: • an aversion to reputational risk • an aversion to regulatory risk / a political response • a sense of social responsibility.	retailers' commercial interests. It may be prudent to revisit this risk within five years, as part of a periodic general review of the regulatory arrangements for using OCCs to manage supply emergencies.
7	Inaccurate inputs and assumptions may cause material inaccuracies in the ERCs.	The system operator must use various inputs and assumptions when determining the ERCs. There is always the risk of inaccuracies in these inputs (eg, inaccurate data provided to the system operator by participants) and assumptions (eg, that short-term market behaviour seeks to minimise use of hydro storage during periods of low inflows). Material inaccuracies in these inputs and assumptions would be likely to cause material	**Impact threshold met** Reaching an OCC, and possibly rolling outages, sooner would have a material adverse impact on security of supply and cause significant economic loss.	**Low likelihood of risk becoming an issue** The system operator takes care with the inputs and assumptions it uses in determining the ERCs and has commissioned several independent reviews of various aspects of its ERCs.	**Regulatory arrangements appear effective** The system operator reviews the inputs and assumptions used in the ERCs in a timely manner. The system operator also publishes the inputs and assumptions used in determining the ERCs, subject to restrictions on confidential information. This provides an opportunity for interested parties to provide the system operator with updated information where those parties consider the ERCs' inputs and

#	Risk area	Risk to security of supply	Initial evaluation: Impact threshold met?	Initial evaluation: Likelihood	Initial evaluation: Effectiveness of current regulatory arrangements
		inaccuracies in the ERCs. This could result in hydro lakes being drawn down faster or slower than is optimal. If they are mistakenly drawn down too quickly, this increases the risk of an OCC being needed and possibly rolling outages.			assumptions to be inaccurate. The willingness of interested parties to provide the system operator with information appears to be good, although there is no regulatory compulsion underpinning this. Given the expected changes to the electricity industry over the coming years (eg, the uptake of distributed energy resources), it may be prudent to revisit this risk within five years, as part of a periodic general review of the regulatory arrangements for using OCCs to manage supply emergencies.

Appendix A Managing supply emergencies

A.1 In addition to OCCs, the Code contains several other arrangements that are intended to give effect to the Act's requirement for the system operator to manage supply emergencies. These arrangements provide for the system operator to manage both energy shortages and capacity shortages.

A.2 This appendix summarises these other regulatory arrangements, grouping them under the headings of 'Managing energy shortages' and 'Managing capacity shortages'.

A.3 A couple of the regulatory arrangements apply to managing both energy and capacity shortages—being supply shortage declarations and urgent temporary grid reconfigurations. These have been placed under the heading 'Managing energy shortages', as they are both in Part 9 of the Code, which is primarily about managing energy shortages.

Managing energy shortages

Emergency Management Policy

A.4 Part 7 of the Code requires the system operator to prepare and publish an emergency management policy (EMP).[35] The EMP must:

(a) set out the steps the system operator must take, and must encourage industry participants to take, at various stages during an extended emergency, such as an extended dry sequence or an extended period of capacity inadequacy

(b) include the steps that, at various stages in anticipation of and during a gas transmission failure or gas supply failure to generators, the system operator must:

(i) take as the system operator

(ii) encourage participants to take, including, if appropriate, steps for relevant participants to take in conjunction with gas industry entities

(iii) encourage relevant gas industry entities to take.

A.5 The Code permits the system operator to depart from the policies in the EMP if:

(a) a situation arises in which the system operator believes on reasonable grounds that complying with the EMP will not:

(i) adequately mitigate an emergency situation, or

(ii) minimise risk to public safety or significant damage to assets, and

(b) such departure is required to enable the system operator to comply with the reasonable and prudent system operator standard set out in Part 7 of the Code.[36]

A.6 The EMP does not relate to management of short-term power system conditions. Those are managed through the system operator's "business-as-usual" obligations under the Code and the policy statement.

A.7 The system operator prepares the EMP, while the Authority approves it. The EMP is incorporated by reference in the Code.

35 Clause 7.3(3)(a).

36 Clause 7.3(5) and clause 7.1A.

System Operator Rolling Outage Plans and Participant Rolling outage plans

A.8 Part 9 of the Code provides for the system operator to prepare and publish a system operator rolling outage plan (SOROP). The SOROP provides for the management and co-ordination of planned outages as an emergency measure during shortages of electricity supply or transmission capacity.[37]

A.9 The SOROP notes there is a range of events that could cause a supply shortage. Some events may develop over time (a developing event) and some events may arise with little or no warning (an immediate event). Examples of events that could contribute to a supply shortage are a period of low hydro inflows or an extended outage of a major transmission line or generating plant.

A.10 If a supply shortage is caused by a power system event, it is likely any supply shortage declaration will be preceded by a grid emergency caused by a deficit of energy or instantaneous reserve. If the grid emergency is likely to persist for a sustained period, the SOROP states that the system operator will make a supply shortage declaration if it considers the supply shortage would be more appropriately managed by rolling outages.

A.11 The system operator prepares the SOROP, while the Authority approves it. The SOROP is incorporated by reference in the Code.

A.12 The SOROP identifies 'specified participants' that must develop a participant rolling outage plan (PROP). A PROP sets out the actions the specified participant will take to achieve, or contribute to achieving, reductions in electricity consumption following a direction from the system operator.[38] Specified participants are distributors, line owners, retailers and direct connect consumers.

Supply shortage declarations

A.13 Part 9 of the Code says the system operator may make a supply shortage declaration, if there is a shortage of electricity supply or transmission capacity such that the system operator considers:

(a) the normal operation of the electricity spot market is, or will soon be, unlikely to facilitate supply always matching demand, and

(b) that, if planned outages are not implemented, unplanned outages are likely.[39]

A.14 The system operator must have regard to the SOROP when making a supply shortage declaration.[40]

A.15 While a supply shortage declaration is in force, the system operator may (in writing) direct specified participants to contribute to achieving reductions in the consumption of electricity by implementing outages or taking any other action specified in the direction.

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37 Clause 9.1 and clause 9.4.

38 Clause 9.8(1).

39 Clause 9.14(2).

40 Clause 9.14(4).

Customer Compensation Schemes, public conservation periods and Official Conservation Campaigns

A.16 Part 9 of the Code provides a framework under which retailers must have a Customer Compensation Scheme (CCS) in place to compensate their qualifying customers during a public conservation period.

A.17 A public conservation period is any period during which:

(a) a supply shortage declaration is in force for at least one week

(b) an OCC is running.[41]

A.18 As noted earlier, an OCC is a campaign to encourage electricity conservation, which the system operator starts and ends, and which:

(a) lasts for at least one week, and

(b) covers either the South Island or all New Zealand.[42]

A.19 The Authority introduced the requirement for retailers to have a CCS in 2011 to address two related problems.

A.20 First, in dry years over the period 2000–2010, electricity retailers had an incentive to lobby government for conservation campaigns as a 'free option' to limit their exposure to high spot prices driven by falling hydro storage. When their customers responded to those campaigns and reduced electricity consumption, retailers that had not otherwise hedged their exposure benefited through reduced purchases in the wholesale electricity market.

A.21 Second, experience in 2001, 2003, and 2008 indicated conservation campaigns had been over-used, and customers were beginning to suffer from 'campaign fatigue'.

A.22 The CCS arrangement in the Code addresses these problems by establishing two principal incentives.

A.23 First, requiring retailers to compensate qualifying customers for their effort saving electricity establishes an incentive[43] for retailers to manage spot price risk more appropriately, such as through financial or physical hedges. Increased hedging in turn acts to increase the overall level of energy reserve available by underwriting investment in generation and demand response capacity. Conservation campaigns then become less likely.

A.24 Second, as conservation campaigns will still be needed in future under some dry year conditions, compensation payments encourage customers to conserve energy when a compensation campaign is called. CCSs further encourage the major hydro generators to manage hydro lake levels more prudently in a year with low inflows, preserving the option of using that water later in the season.[44]

A.25 The Authority specifies a minimum weekly amount that retailers must pay to their qualifying customers during an OCC. Currently, the minimum weekly amount is $10.50.

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41 Clause 1.1(1).

42 Clause 1.1(1), clause 9.23, and clause 9.23A.

43 Avoiding the need to pay such compensation.

44 Electricity Authority, 18 October 2016, Review of the customer compensation scheme: consultation paper, p. ii. Available at: https://www.ea.govt.nz/assets/dms-assets/21/21363Review-of-the-customer-compensation-scheme-consultation-paper.pdf.

Urgent temporary grid reconfigurations

A.26 To improve security of supply, Part 9 of the Code also provides for the system operator to request the grid owner:

(a) to temporarily remove one or more interconnection assets from service, or

(b) to temporarily reconfigure the grid.[45]

Managing capacity shortages

Principal Performance Obligations

A.27 Part 7 of the Code sets out principal performance obligations (PPOs) that the system operator must meet in relation to common quality and dispatch.

A.28 The PPOs play an important role in the system operator's management of supply emergencies.

A.29 The first PPO requires the system operator to maintain frequency during contingent events and extended contingent events. These are events on the power system due to an asset failure that may result in cascade failure.

A.30 The policy statement, which is required under Part 8 of the Code, defines contingent events and extended contingent events and sets out the policies the system operator follows to manage supply emergencies arising because of these events. Refer to the discussion below under the heading '*The policy statement*'.

A.31 The last PPO provides for industry participants to request the system operator to investigate and resolve a security of supply or reliability problem arising from non-compliance with a standard in the following clauses of the connection code:

(a) clause 4.7—harmonic levels

(b) clause 4.8—voltage flicker levels

(c) clause 4.9—voltage imbalance of less than 1%.

A.32 Such a request can be in relation to any point of connection to the grid.

A.33 If the system operator finds there to be a security of supply or reliability problem, the system operator must identify the cause of the problem and resolve the problem, to the extent that it is reasonable and practicable to do so.

A.34 Transpower prepares the connection code, while the Authority approves it. The connection code is incorporated by reference in the Code.[46] It forms schedule 8 of the benchmark agreement, which is also incorporated by reference in the Code.[47]

Policy statement

A.35 Part 8 of the Code requires the system operator to prepare a 'policy statement', which sets out policies and means that the system operator will use to meet the PPOs. The policy statement includes policies for dealing with power system events that can have large adverse reliability of supply effects. The security policy within the policy statement includes:

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45 Clause 9.13B.

46 Clause 12.26.

47 Clause 12.34.

(a) how commonly occurring events are to be managed, with the intention being to avoid exceeding frequency limits and asset capability (including voltage limits)

(b) the use of automatic under-frequency load shedding (AUFLS) to manage extended contingent events, where demand may otherwise be shed to maintain the security policy and the requirement for emergency management procedures to manage extreme events

(c) dealing with emergencies relating to security issues—noting that these policies in the policy statement do not limit the system operator's powers under the main body of the Code in relation to emergencies.

A.36 The security policy says the system operator must seek to manage the outcomes of events that may cause cascade failure by:

(a) identifying, on at least a five-yearly basis, potential credible events on the power system due to an asset failure that may result in cascade failure

(b) estimating the likely risks based on the potential impact of the event(s) on the power system

(c) categorising the credible event as one of the following:

(i) a contingent event—an event where the impact, probability of occurrence and estimated cost and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and dispatch processes pre-event[48]

(ii) an extended contingent event—an event for which the impact, probability, cost and benefits are not considered to justify the controls required to totally avoid demand shedding or maintain the same quality limits defined for a contingent event[49]

(iii) a stability event—severe power system faults for which it is deemed prudent to ensure the transient and dynamic stability of the power system is maintained

(iv) other event—an event for which feasible controls cannot be justified or do not exist or have not been identified, other than unplanned load shedding, AUFLS, and other emergency procedures

(d) where possible, applying certain principles in implementing controls for each category of risk (eg, for extended contingent events the system operator must plan to maintain the quality levels set out in clause 17.2 of the policy statement through a combination of AUFLS, the provision of reserves, asset redundancy, demand shedding, and the acceptance of greater quality disturbances than for contingent events).[50]

A.37 The system operator can depart from the policies set out in the policy statement when:

(a) a system security situation arises, and

48 Policy Statement, 19 December 2018, p. 8, clause 12.3.

49 *Ibid*

50 Policy Statement, 19 December 2018, p. 8, clause 12.

(b) such departure is required for the system operator to comply with the reasonable and prudent system operator standard set out in Part 7 of the Code.[51]

A.38 The Code defines a system security situation to be a situation that the system operator believes on reasonable grounds is not adequately mitigated by the policy statement and one of the following exists:

(a) the system operator reasonably considers that its ability to comply with the PPOs is at risk

(b) there is a risk of significant damage to assets

(c) public safety is at risk.[52]

A.39 The system operator prepares the policy statement, while the Authority approves it. The policy statement is incorporated by reference in the Code.

Grid emergencies

A.40 Part 8 of the Code provides for the system operator and participants to anticipate and respond to emergency events on the grid that affect the system operator's ability to plan to comply, and to comply, with its PPOs.

A.41 The Code defines a grid emergency to be where:

(a) in the reasonable opinion of the system operator, one or more of the following events has occurred, or is reasonably expected to occur and urgent action is required of the system operator or participants to alleviate the situation:

(i) the ability of the system operator to plan to comply, and to comply, with the PPOs is at risk or is compromised (as set out in the policy statement)

(ii) public safety is at risk

(iii) there is a risk of significant damage to assets

(iv) independent action has been taken by generators and ancillary service agents to restore the system operator's PPOs,[53] or

(b) extreme levels of frequency or voltage require a fast and independent response from each generator and each ancillary service agent.[54]

A.42 If the system operator declares a grid emergency:

(a) a generator cannot reduce the MW specified in any of its offers for the trading periods and grid injection points affected by the grid emergency, unless:

(i) the generator has a bona fide physical reason that necessitates the reduction, or

(ii) the generator increases equivalent offered MW at other generating plant in the electrical or geographical region affected by the grid emergency, and

51 Clause 8.14.
52 Clause 1.1(1).
53 Clause 1.1(1) and clause 5 of Technical Code B of Schedule 8.3.
54 Clause 1.1(1) and clause 9 of Technical Code B of Schedule 8.3.

(b) an ancillary service agent cannot reduce the instantaneous reserve specified in any of its reserve offers for the trading periods and grid points of connection affected by the grid emergency, unless:

(i) the ancillary service agent has a bona fide physical reason that necessitates the reduction, or

(ii) the ancillary service agent increases equivalent offered instantaneous reserve at other grid points of connection in the electrical or geographical region affected by the grid emergency,[55] and

(c) a purchaser cannot increase the aggregate quantity of electricity specified in all of the purchaser's nominated bids for the trading periods and grid exit points affected by the grid emergency unless:

(i) the purchaser has a bona fide physical reason that necessitates the increase,[56] or

(ii) the purchaser bids equivalent decreased quantities in substitution, for grid exit points in the electrical or geographical region affected by the grid emergency, and

(d) a purchaser must immediately change any nominated dispatch bid to a nominated non-dispatch bid, if the bid is for:

(i) a grid exit point in the electrical or geographical region affected by the grid emergency, and

(ii) a trading period affected by the grid emergency.[57]

A.43 If an unexpected event occurs giving rise to a grid emergency, the system operator may take any reasonable action to alleviate the grid emergency. This includes:

(a) requesting generators to vary their offers

(b) requesting purchasers or connected asset owners to reduce their demand

(c) requiring the grid owner to reconfigure the grid

(d) emergency load shedding.

Dispatch objective

A.44 Part 13 of the Code sets out the system operator's dispatch objective. This is to maximise the benefit to purchasers from buying electricity after accounting for the cost of producing electricity and providing ancillary services.[58]

A.45 The dispatch objective is an important regulatory arrangement for managing capacity-based supply emergencies. This is because it incorporates the use of instantaneous reserves to cover the largest identified contingent event risk (in MW).

55 Clause 13.97 and clause 13.98.
56 Clause 13.99 and clause 13.100.
57 Clause 13.99A.
58 Clause 13.57.

A.46 The dispatch objective can only be deprioritised during restoration of the power system following an event that disrupts the system operator's ability to comply with the PPOs.[59]

[59] Clause 8.5.