Electricity Commission
Te Komihana Hiko

Development of a Capacity Adequacy Standard

October 2008

Executive summary

1. The Electricity Act 1992 (Act) and the Government Policy Statement on Electricity Governance (GPS) establish a responsibility for the Electricity Commission (Commission) to manage the security of supply of electricity.

2. In reviewing the security of supply policy in 2007, the Commission conveyed an intention to develop a standard for capacity adequacy to complement the standards for energy adequacy. The Government Policy Statement (GPS) issued in May 2008 reflected this intention.

3. This paper summarises the outcome of applying an economic approach to estimating an optimal standard and trades off the costs of capacity shortfalls against the costs of adding reserve capacity. The Commission has considered a broad definition of capacity adequacy, with the analysis capturing variations to demand and supply contingencies across the whole year rather than just at times of highest demand (historically in winter evenings).

4. The analysis captures the interaction between supply and demand on a probabilistic basis, focussing on North Island adequacy. Consideration of a South Island capacity margin is not considered necessary at this point given the surplus of South Island capacity over “peak” South Island demand.

5. The standard is expressed as a minimum 780MW margin of derated North Island supply over the average of the highest 200 half-hours of winter North Island daytime demands. North Island supply includes the contribution of supply from the South Island accounting for the South Island supply/demand balance and HVDC capability.

6. The 780MW standard is intended to apply to 2012, at least. This standard is consistent with achieving an economic trade-off for a range of plausible new supply and demand scenarios over this time. The level of the margin should be reviewed by 2012, or if there is a significant change in the key assumptions (e.g., supply mix or the assessed costs of capacity shortfalls).

7. The Commission will include an assessment of capacity adequacy within its annual security assessment. If a future assessment does highlight concern with projected capacity levels, the Commission could respond in a number of ways, ranging from measures to make best use of existing capacity to procuring capacity itself, as outlined in the Security of Supply Policy.

Glossary of abbreviations and terms

Ancillary service	The system operator has contracts with generators, customers, retailers and distributors to provide ancillary services, which comprise black start, over frequency reserve, frequency keeping reserve (also known as frequency regulating reserve), instantaneous reserve and voltage support. The system operator obtains instantaneous reserve on a half-hourly basis through the market.
AUFLS	Automatic Under-Frequency Load Shedding
Automatic under-frequency load shedding	Automatic shedding of electrical load to avoid cascade failure when frequency falls below a preset frequency
Base-load Generation	Electricity generation that is designed to operate continuously for most of the year (typically with high fixed costs and low running costs)
Brown out	A drop in voltage in an electrical power supply, so named because it typically causes lights to dim, as distinguished from a blackout, which is a total power failure or power outage.
Capacity	The capability of generating plant to produce energy per unit of time (often expressed in megawatts)
Capacity adequacy	Having enough capacity to meet high levels of demand while allowing for generation plant outages
Capacity demand curve (CDC)	A LDC adjusted for uncertainty in demand forecasts and supply outages
Capacity margin value (CMV)	The MW value used for a component of supply in the calculation of the capacity margin
Capacity shortfall	A situation where available supply cannot meet demand plus losses, reserves, and frequency keeping.
Capacity shortfall curve (CSC)	A cumulative distribution of capacity shortfalls
Combined cycle generation	Combined cycle is a term used when a power producing engine or plant employs more than one thermodynamic cycle. Heat engines are only able to use a portion of the energy their fuel generates (usually less than 50%). The remaining heat from combustion is generally wasted. Combining two or more "cycles" results in improved overall efficiency.

Consumption	The electrical energy consumed by a 1,000 watt (1 kilowatt) appliance in an hour is one kilowatt-hour (kWh). A kilowatt-hour is also known as a ‘unit of electricity’ and is the unit in which retail sales of electricity are measured.
Demand side initiative	An initiative that encourages or facilitates electricity consumers to modify their usage in way that reduces consumption in a specific time period or shifts consumption from one time period to another.
Dispatch instruction	An instruction issued by the system operator to generators and ancillary service agents in accordance with the dispatch schedule.
Dispatch prices	Dispatch prices are forecast prices calculated in the four hours before dispatch takes place. Dispatch prices are produced in the schedule of dispatch prices and quantities (SDPQ) and are generally more accurate than prices from the pre dispatch schedule (PDS).
Dispatch schedule	The schedule which the system operator bases dispatch instructions on to achieve the dispatch objective.
Distributor	A company that owns or operates the power lines that transport electricity on local low voltage networks.
Domestic consumer	Users of electricity for personal, domestic or household use. This does not include users who purchase electricity for re-supply, or for use in production or manufacture.
Electricity Act 1992	The Act, as amended by later Acts, that regulates the New Zealand electricity industry, and under which the Commission operates.
Electricity Commission	The Electricity Commission established under subpart 1 of part 15 of the Electricity Act, also known as the Commission. The Commission is composed of six members appointed by the Minister of Energy to oversee the governance, operation and development of the New Zealand electricity industry.
Embedded generation	Generation that is connected to a local network rather than to the national grid.
Energy adequacy	Having enough generating plant and fuel to meet electricity demand over a defined time period
Expected Capacity	An estimate of electricity capacity over a particular period of time (MW), and not necessarily corresponding to the pure arithmetic average
Expected Demand	A mean estimate of electricity demand over a particular period of time (GWh or MW)
Expected Supply	A mean estimate of electricity generation over a particular period of time (GWh or MW)

Forced outages	Outages of generation or transmission equipment that are unexpected or un-scheduled
Forecast price	Forecast prices are calculated from the pre dispatch schedule (PDS) up to 35 hours ahead of the start of any half-hour period and every two hours from then until the start of the specific trading period.
Frequency	The frequency of the New Zealand grid is normally maintained at 50 Hertz frequency.
Frequency Keeping Reserve or Frequency Regulating Reserve (FRR)	An ancillary service used to keep the frequency of the grid within its normal band of 50±0.2Hz. Frequency keeping stations increase or decrease generation within a set band to ensure that supply equals demand on a second by second basis.
Generator	A company that generates electricity connected to the grid or a local network.
Gigawatt hours (GWh)	One gigawatt hour is equal to one million kilowatt hours. New Zealand's annual demand is approximately 40,000 GWh, excluding losses.
Grid	The high-voltage electricity transmission network, which transmits electricity throughout New Zealand over more than 12,000km of transmission lines, from generators to distributors and major industrial users. It is also referred to as the national grid, and it is owned by state-owned enterprise Transpower.
Grid Injection Point (GIP)	A point of connection where electricity flows into the national grid from generating stations.
Grid exit point (GXP)	A point of connection where electricity flows out of the national grid to local networks or direct consumers.
Grid owner	Transpower is the owner of the high voltage transmission grid, also referred to as the national grid.
HVDC	High Voltage Direct Current transmission link which runs between Benmore in the central South Island, and Haywards near Wellington. A section of the link runs under Cook Strait via submarine cables.
Hydro spill	Hydro spill refers to water flowing past a power station that is not being used to generate electricity.

Instantaneous reserves (IR)	Generation capacity that is made available to be used in the event of a sudden failure of a generating or transmission facility in order to maintain system frequency at above 48 Hz. Fast instantaneous reserve is available within six seconds and must be able to operate for one minute. Sustained instantaneous reserve is available within 60 seconds and must be available for 15 minutes.
Interruptible load (IL)	A type of instantaneous reserve that is provided by load that can be quickly disconnected, e.g. hot water heating.
Involuntary demand restraint	Involuntary restraint (or outages) can occur either from Automatic Under Frequency Load Shedding (AUFLS) during a system contingency (tripping of a large generation unit or transmission line), or from pre-contingent load shedding instructed by the System Operator.
Kilowatt-hour (kWh)	A kilowatt-hour is also known as a ‘unit’, and is the basis of retail sales of electricity.
Load duration curve (LDC)	A distribution of annual half-hour demands sorted from highest to lowest.
Load probability curve (LPC)	A LPC is based on the average of many LDC forecasts.
Load Shedding	The forced disconnection of load, in stages. This is either manual or automatic
Local network	The lines and substations used by distributors to transport electricity from grid exit points (GXPs) to points of connection with consumers.
Long-run average supply	The average generation from a generation facility such as a wind farm or hydro plant calculated over many years of history.
Losses	As electricity travels through the national grid, a proportion of energy is lost as heat due to the resistance in the lines. The greater the distance the electricity travels and the lower the voltage of the line, the higher the losses are.
Megawatt hour (MWh)	One megawatt hour is equal to 1,000 kilowatt hours. Megawatt hours are the metering standard unit for the wholesale market.
NZEM (New Zealand Electricity Market)	The multi-party trading arrangement under which, until 1st March 2004, the majority of New Zealand’s wholesale electricity was bought and sold.
National grid	The transmission network that transports high-voltage electricity from the major power stations to the local distribution networks operated by lines companies. It is also known as the grid and is owned by Transpower.

Network	The grid, a local network or an embedded network.
Nodal pricing	In New Zealand the nodal price is calculated for approximately 244 market nodes, in addition to over 200 transfer nodes.
Node	A point on the national grid where electricity either enters or exits the grid (a grid injection point or a grid exit point) or flows through (a transfer node).
Offer	An offer to sell a quantity of electricity at a specified price.
PDS (Pre Dispatch Schedule)	This schedule is produced by the system operator, and includes expected levels of generation, instantaneous reserves, demand and forecast energy and reserve prices. If produced before 13:00 hours, the PDS covers the remaining trading periods of the day. If produced after 13:00 hours, it covers the remaining trading periods of the day and the trading periods of the following day.
Reserve	Energy that can be produced within seconds to maintain frequency in the event or generation or transmission line outage.
Retailer	A company that sells electricity to customers.
Scheduled outages	Outages of generation or transmission equipment that are planned to occur (typically to allow for maintenance)
Spot market	The buying and selling of wholesale electricity is done via a ‘pool’, where electricity generators offer electricity to the market and retailers and major users bid to buy the electricity. This market is called the spot or physical wholesale market.
Spot price	The half-hour price of wholesale (‘spot’) market electricity published by the pricing manager.
System Operator (SO)	Service provider responsible for scheduling and dispatching electricity, in a manner that avoids fluctuations in frequency or disruption of supply. The system operator is currently Transpower.
Transpower	The state-owned enterprise which owns the high-voltage transmission network (the national grid) and is the system operator.
Voltage support	Reactive support capabilities procured in regions of the grid (Auckland and top of South Island) to support voltage. The services are procured from generators.
Voluntary demand restraint	Demand reductions that occur in response to market participants forecasting a risk of high prices, or in response to System Operator warnings. It can also be contracted demand-side response

Winter Energy Margin	The difference between the expected amount of energy that can be supplied and expected demand during the period 1 April to 30 September, expressed as a percentage of expected demand
Winter Capacity Margin	The MW difference between a measure of the expected capacity and the average of the highest 200 half-hours of demand from 1 April – 31 October between 7am and 10pm.

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1.1.3 This paper explains the work undertaken by the Electricity Commission (Commission) to develop the form and level of the capacity adequacy standard included in its Security of Supply Policy.

1.1.4 In particular, it:

(a) Discusses the motivation for the work and analytical approach;

(b) Describes the form and level of a capacity adequacy standard to be incorporated in the Commission's security of supply policy and used for Annual Security Assessments; and

(c) Summarises additional work undertaken since consultation in May.

1.1.5 The standard is intended to apply out to 2012 by which time the GPS indicates the Commission's Security of Supply Policy will be reviewed.

2. Background

2.1.1 The Review of Reserve Energy Policy undertaken by the Commission during 2007 focussed on a security standard for energy adequacy. The recommended "energy margin" that emerged from the review represents an ability to supply electricity over time, while allowing for dry periods.

2.1.2 Many international security of supply standards focus on capacity adequacy in order to assess the ability to supply high electricity demand at any point in time. They focus on capacity adequacy because they are "peak-constrained" rather than "energy-constrained" – in other words they need to construct new supply in order to meet very high (peak) demands over a short time frame rather than supply energy over a longer time frame.

2.1.3 Historically, New Zealand has not had a capacity problem because of the high proportion of hydro capacity with associated flexible fuel supply (storage). We have tended to construct new power station capacity in order to supply energy over time rather than to meet peak demand – in other words New Zealand has been considered as "energy-constrained"

2.1.4 In recent times, the retirement of New Plymouth power station, the growth in peak demand, and the addition of intermittent generation in the form of wind farms, has eroded the margin between capacity and demand at peak times.

2.1.5 The tight supply/demand situations that emerged in June 2006 and February 2008 are indicative of this change. With Government policy favouring renewable supply sources over fossil-fuelled sources, the resilience of the electricity system to meet peak demands is expected to come under further pressure.

2.1.6 In its role of ensuring Security of Supply, the Commission has routinely assessed energy adequacy (supply adequacy over longer time frames), with a forecast breach of requirements having the potential outcome of procurement of reserve energy. Until now, there has been no corresponding metric for assessing capacity adequacy or 'peak' adequacy (supply adequacy over short durations). In its recommendations to the Minister in November 2007 regarding the independent review of Reserve Energy Policy, the Commission conveyed an intention to develop a standard for capacity adequacy to complement the energy adequacy standard. This was subsequently reflected in the GPS issued in May 2008.

2.1.7 In its review of the Commission's Reserve Energy Policy undertaken during 2007, Castalia Strategic Consultants recommended that an energy security standard be assessed by trading off the costs of reserve plant against the costs of demand restraint. It is possible to apply a similar methodology to deriving a capacity adequacy standard.

2.1.8 This paper outlines the approach that has been used for developing a capacity adequacy standard and the conclusions regarding the form and level of that standard to be included in the Security of Supply Policy. The intention of this paper is to explain the rationale, analysis, and assumptions underlying the form and level of capacity adequacy standard defined in that policy (but not to discuss or explain the policy directly).

3. Measuring Capacity Adequacy

3.1 Key terms and concepts

3.1.1 The term “peak” demand is often used to distinguish demand over short durations (usually expressed in MW) from “energy” demand, which is demand over longer durations (usually expressed in MWh or GWh). When contemplating capacity adequacy, it is the ability of the power supply system to meet the instantaneous demand for electricity at all times that is important. This naturally tends to focus interest on times of peak demand. However, there can be factors which limit supply at other times of the day or year (e.g., due to supply contingencies) and a capacity adequacy standard needs to capture those situations as well. So for this paper we have chosen to use the term “capacity adequacy” to reflect the ability of supply to meet demand during periods of stress, either high demand and or plant break downs.

3.1.2 When considering capacity adequacy, a key issue to address is what should be ‘counted’ when considering the ability of supply to meet demand. The supply chain connecting generation with demand includes transmission and distribution networks. There can be a number of contingencies throughout the supply chain and it is important to recognise that the security of supply experienced by end-consumers results from the combined reliability of fuel supply, generation, transmission and distribution.

3.1.3 For transmission and distribution, the linkage between the state of the networks, investment, and the impact on demand are addressed by existing standards and regulatory frameworks:

(a) For the transmission network, grid reliability standards drive reliability investments; and

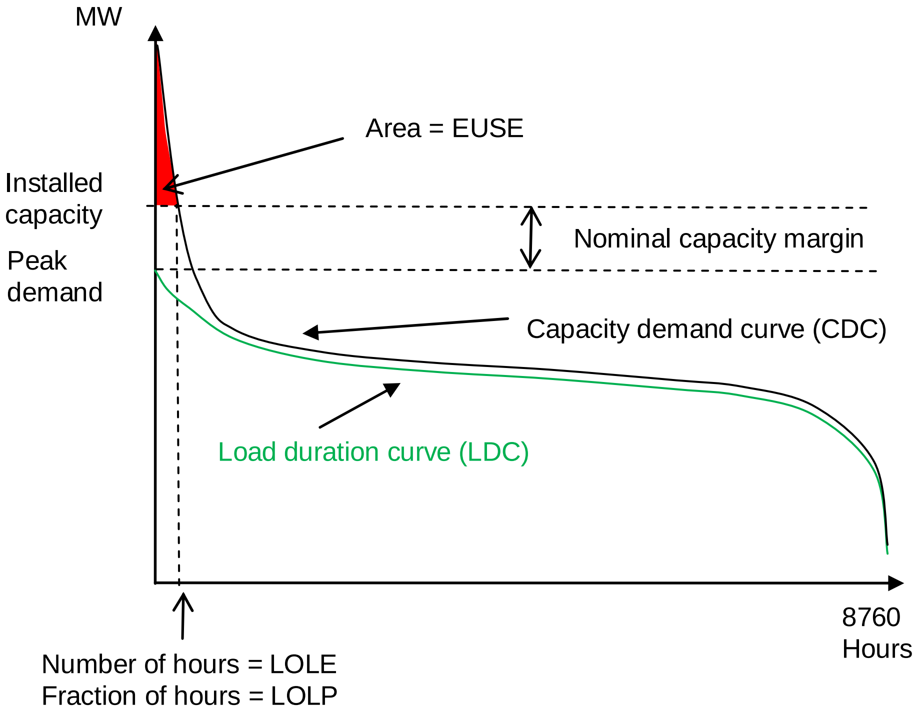
(b) For distribution networks, the Commerce Act regime includes measures relating to the frequency and duration of outages caused by contingencies in the network.

3.1.4 A capacity adequacy standard is intended to assess the capability of the generation system to meet electricity demands. Accordingly, the transmission and distribution networks are only considered where they constrain the ability to deliver generation MW to consumers in general. For example, if there was a significant capacity shortfall in the North Island, then capacity across the inter-island HVDC transmission could limit the extent to which South Island supply may contribute to meeting that demand.

3.1.5 For the development of the capacity adequacy standard the focus has been on the sources of disruption to generation supply (e.g. wind and water availability and plant breakdowns), and the variability of demand. The principle applied to transmission is to account for limitations of the HVDC link and, if relevant, any other major transmission constraints that could limit the interconnection of generation with demand.

3.1.6 Figure 1 illustrates some of the key concepts of supply adequacy. Demand variability is represented by a load duration curve (LDC), which is expected or forecast half-hours of demand (inclusive of losses) over a year ranked from highest to lowest. The capacity demand curve (CDC) includes uncertainty in demand forecasts and supply outages. The red area indicates where the demand for capacity exceeds the installed capacity. In these half hours a capacity shortfall exists and load shedding is required.

Figure 1: Conceptual measures of supply adequacy



3.1.7 Several measures of adequacy can be derived from this figure:

(a) Expected unserved energy (EUSE): the expected involuntary restraint measured in MWh (MW of restraint x duration). Often the EUSE is expressed as a fraction of annual energy demand. EUSE reflects both the depth and duration of any involuntary restraint.

(b) Loss of load expectation (LOLE): the expected number hours of involuntary restraint, also equivalent to the number of hours that the CDC exceeds capacity. LOLE does not reflect the magnitude of any outages.

(c) Loss of load probability (LOLP): the LOLE expressed as a fraction of hours per annum.

(d) Nominal capacity margin: a measure of the MW difference between nominal (installed) capacity and a measure of peak demand (from the LDC). For example, an expected peak demand (P50) might be used. The MW margin is often expressed as a percentage of peak demand. As will be discussed later, other versions can be calculated where nominal capacity is de-rated to reflect expected capacity at peak, and where demand is expressed differently.

3.1.8 A capacity adequacy standard can be expressed as a particular value of one of these measures.

3.2 International experience

3.2.1 Many deregulated electricity markets have some form of capacity adequacy standard (note that the equivalent is often referred to as a “reliability standard”). Because supply mix, market design, and regulatory environments differ markedly, care is required in attempting to compare overseas standards with that which might apply in New Zealand. Nevertheless, there is merit in examining the approach that is taken and the nature and magnitude of overseas standards.

3.2.2 Table 1 summarises the type of standard, the level of standard, the basis for the standard and the scope of application.

Table 1: Capacity adequacy standards in overseas markets

Country	LOLE	EUSE	Basis for standard	Scope
Australia (NEM)		.002%	Defined by Reliability Panel in 1998 at market start and confirmed by AEMC in 2007 when reviewed	Generation and bulk transmission. Single credible contingencies of generation or bulk transmission
Australia (WA)	MW margin (largest unit) or .002% EUSE		Unclear	Generation and bulk transmission. Prudent peak demand
Ireland	8 hours per annum		“Appropriate and acceptable” on historic basis	Ability of grid connected generation to meet GIP demand. Transmission limits, but not risks

Country	LOLE	EUSE	Basis for standard	Scope
UK	No formal standard		Monitor and contemplate economic trade-off, but" far from straightforward in practice"	Nominal capacity and "average cold spill" peak demand.
France	3 hours per annum		Government decision	Grid connected supply. Transmission outages and imports
PJM	2.4 hours per annum (one day in 10 years)		Formulation of NERC in 1965	Generation capacity. No transmission risk. LOL = invoking emergency operations procedures beyond demand resources and IL for reliability
Ontario	2.4 hours per annum		Follows NPCC standard (Northeast Power Coordinating Council)	Ad hoc transmission adjustments on supply

3.2.3 From this sample, it is clear that different countries adopt different approaches to developing and specifying a standard. In markets where a standard is defined, there are subtle differences in the way demand restraint and uncertainties are measured, often capturing the features of the particular market. It is not always clear what the implications of breaching a standard are or what the mechanisms for intervention might be.

3.2.4 There is reasonable consistency in the level of LOLE standards (ranging from 2.4 to 8 hours per annum). The LOLE corresponding to the .002% EUSE standard employed in Australia was recently estimated as 3.5 hours per annum and providing a 16% installed capacity margin over peak demand. In Western Australia, a market with a similar size to the North Island of New Zealand, a 320 MW margin is used corresponding to the largest supply contingency.

3.2.5 The basis upon which standards are defined is often non-scientific (USA, Australia, and Ireland). In the United Kingdom there is no specified standard, but capacity margins are monitored on a regular basis. The Australian NEM standard was reviewed in 2007, with EUSE preferred over alternative measures due to it being familiar, easy to measure, reflective of the economic impact on typical users, and equally applicable to different regions.

3.2.6 While there are nuances in the way in which adequacy standards are expressed, there is reasonable consistency about scope, with transmission and distribution uncertainties typically excluded, and supply/demand variation included. Of particular importance is a clear definition of the various components of demand and how they are accounted for.

3.2.7 As illustrated earlier, the individual measures are not separable; selecting one measure of capacity adequacy implies values for the other measures (for example the .002% EUSE adopted in the NEM has recently been assessed as equivalent to a LOLE of 3.5 hours per annum). In defining a standard, the rationale for selecting one measure over another needs to be consistent with the approach used to derive the measure and the intended consequences if it is not met.

3.3 Developing the standard using an economic approach

The Concept of an Economic standard

3.3.1 It would be possible for New Zealand to arbitrarily set a standard on the basis of international norms or a judgemental assessment of “good practice”. However this begs the question as what is the underlying basis of these standards and if they are appropriate to apply in New Zealand.

3.3.2 The Commission therefore decided to go back to first principles and determine the underlying economic capacity adequacy standard as recommended by the Castalia Review. This involves finding the optimal level of capacity adequacy that balances the cost of back up peaking capacity against the cost of demand restraint and outages.

3.3.3 This economic standard appropriate for New Zealand conditions can then be cross checked against international practice. Any significant difference can then be investigated to see if this can be explained in terms of shortage cost, capacity cost and system features. It also provides a robust and repeatable framework for assessing the implications of alternative cost and plant assumptions as New Zealand’s electricity market, and plant mix, evolves.

3.3.4 The Commission considered three different approaches to deriving the economic capacity adequacy standard; a simple theoretical approach, a LDC convolution approach and a chronological simulation approach.

A simple theoretical approach

3.3.5 It is possible to calculate an optimal LOLE or LOLP standard directly from the cost of peaking capacity and the cost of capacity shortfalls.

3.3.6 This is given by LOLE = F/CS.[1] where

- the fixed annual cost of a peak supply plant (F $/MW/yr) and
- the net cost of capacity shortfalls is assumed to be constant (CS $/MWh).

3.3.7 For example, this would imply an LOLE of 6.2hrs/yr if the fixed cost of a peak supply plant is $124,000/MW/yr and the cost of capacity shortfall is $20,000/MWh.

3.3.8 The Commission decided against this approach since it could not be used to derive other measures of capacity adequacy (EUSE and capacity margin), and because the cost of capacity shortfalls depends on the depth of the shortfall (shortfalls of up to 300MW met by relaxing instantaneous reserve requirements are an order of magnitude less costly than instructed load shedding).

LDC convolution approach

3.3.9 A more complex approach is required to recognise that the cost of a capacity shortfall depends on the depth of shortfall, and to derive alternative measures such as EUSE and capacity margin in addition to the LOLE.

3.3.10 The simplest alternative approach is the LDC convolution approach. This involves taking the probability distribution of system loads (the LDC incorporating demand uncertainty) and subtracting the probability distribution of supply capacity (accounting for plant outages and other factors affecting supply capability) to derive a capacity shortfall probability curve (CSC). This identifies the probability of exceeding different levels of capacity shortfall.

3.3.11 The expected cost of shortfalls calculated from this curve can account for the depth (MW) of shortfall. These calculations can be repeated for different levels of peak supply capacity (i.e. by adding extra open cycle gas turbine peaking plant) and the total cost of outages and supply capacity can be plotted and a minimum total cost can be found.

3.3.12 The expected hours or quantity of demand restraint (megawatt hours) and outages at this optimum can be derived as well as the optimal capacity margin. These measures can be considered as candidates to represent the economic standard.

3.3.13 Mathematical techniques for performing these calculations are well developed and are used regularly in power systems around the world. This approach was

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[1] This was given in the Castalia Review (May 2007, page 39). Castalia calculated LOLE= 3hrs using this approach, but this was based on $90,000/MW/yr cost for peak capacity and a fixed CNS at $30,0000. 3 = 90,000/30,000. For the Australian NEM analysis McClennan Magasinik Associates used a typical peaker cost of $A100,000/MW/yr and a CNS of $A30,000/MWh. This would imply a LOLE of 3.3 hrs/year.

successfully applied in New Zealand to assess winter 2008 capacity adequacy in the Annual Security Assessment carried out in October 2007.

3.3.14 While this LDC approach is best suited to flexible thermal systems or hydro systems with significant storage; it can be adapted to systems with less flexible hydro, run of river hydro, inflexible cogeneration, and other intermittent generation (e.g. wind, tidal). It is also possible to account for correlations between wind supply and demand if this proves significant, and to account for scheduled outages and seasonal variations in wind and uncontrolled hydro by applying the approach to separate time zones and combining the results.

Chronological Approach

3.3.15 A limitation of the LDC convolution approach is that it does not explicitly address chronological issues i.e., aspects of system security that relate one period to the next such as hydro and thermal ramping constraints, unit commitment/start-up limits, and river-chain scheduling limits.

3.3.16 To properly account for the chronological constraints it would be necessary to go to a significantly more complex simulation which involves modelling the operation of the whole system on a period-by-period basis over a typical day or week for each season taking into account demand uncertainty (including ripple control of load), transmission capacity and HVDC outages, wind uncertainty, hydro inflow uncertainty, reservoir storage uncertainty, forecast accuracy, river chain scheduling constraints, thermal start up times and participant behaviour in response to forecast prices and risks.

3.3.17 There was some doubt that a full chronological model would be necessary given the very significant uncertainty regarding the underlying key parameters such as the cost of supply shortfalls and the cost of new peaking capacity. So initial work focussed on implementing the LDC approach and carrying out some sensitivity testing to determine if additional chronological modelling might be needed to refine the calculations.

Consultation

3.3.18 The Commission issued a consultation paper on May 13, 2008. This paper derived some initial results from implementing this LDC convolution approach and pointed out some of its limitations and asked for submissions on the most appropriate methodology to use in New Zealand.

3.3.19 The key conclusions relating to the proposed methodology were that:

(a) An economic approach should be used to develop a standard on the basis of trading off the costs of capacity shortfall against the costs of reserve capacity;

(b) Using a “load duration curve (LDC) convolution” approach is suitable for measuring the depth and duration of capacity shortfalls;

(c) Further work on assessing chronological issues was required to confirm the approximations made in the LDC convolution approach.

3.3.20 As part of the consultation process, a workshop was held on 6 June with an open invitation to any interested parties. Given the complexity of the methodology, Commission staff considered that there was merit in a face-to-face discussion between stakeholders and staff undertaking the analysis, so as to increase the efficacy of written submissions and improve any other aspects of the analysis and assumptions. Subsequent feedback indicated that participants found this approach efficient and useful.

3.3.21 Submissions were received from Mighty River Power, Genesis Energy, Meridian Energy, Contact Energy, Transpower, PowerCo, Vector, and MEUG. A summary of submissions is included as Appendix 1.

3.3.22 The submissions were generally supportive of establishing and monitoring against a capacity adequacy standard, using an economic approach to establish the standard, the modelling approach that was proposed, and the assumptions used in the analysis.

3.3.23 Although there was good support for establishing a standard, there was general concern expressed by submitters about how the Commission would use the standard. These concerns centred on the possibility that, if capacity adequacy fell below the standard, the Commission might intervene too soon by contracting for reserve capacity[2]. An approach based on monitoring and publishing medium-term assessments, and providing participants with the opportunity to respond to any forecast shortfalls, appeared to have support.

Supplementary Chronological analysis

3.3.24 Subsequent to the consultation, additional analysis was undertaken using a chronological simulation model which overlaid historic supply and demand with outage assumptions and provided a framework for examining the impact of chronological issues (see Appendix 4). Each chronological issue was analysed and a de-rating factor (in MW) was derived to reflect the expected overall effect on MW availability at times of high demand and/or supply contingencies. The supply assumptions presented in Appendix 2 incorporate the conclusions from the chronological modelling.

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[2] In this paper “reserve capacity” is used to denote additions to reserves that are contemplated for capacity adequacy reasons, in order to distinguish from “reserve energy” which is used to denote additions to reserves that are contemplated for energy adequacy reasons.

4. A capacity adequacy standard

4.1 Implementing the LDC convolution approach

4.1.1 A simple description of the LDC convolution approach is given here. Appendix 5 provides a description at a more technical level.

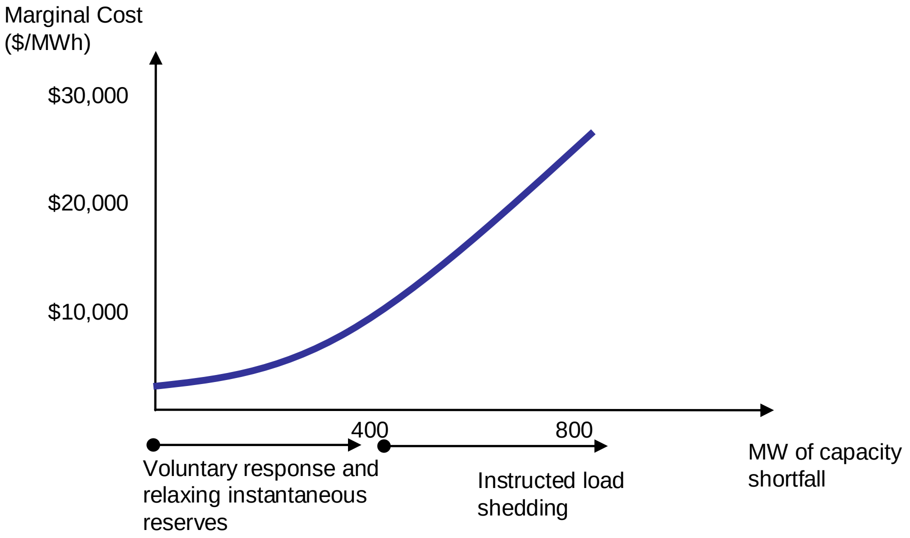
4.1.2 The LDC convolution approach involves the following steps:

(a) Distributions of supply and demand are generated for each island, reflecting the uncertainties in supply and demand as discussed in the previous section.

(b) Using a Monte Carlo simulation, the supply and demand curves are sampled and the contribution to North Island demand from South Island supply is calculated (adjusted for HVDC transmission constraints and reserve requirements). The output is the capacity shortfall probability curve (CSC) providing a probability distribution of possible capacity deficits.

(c) For a given mix of power stations representative of the current system, the CSC can be used to derive an expected cost of capacity shortfall (or EUSE) using an increasing cost of capacity shortfall function as illustrated in Figure 2 below.

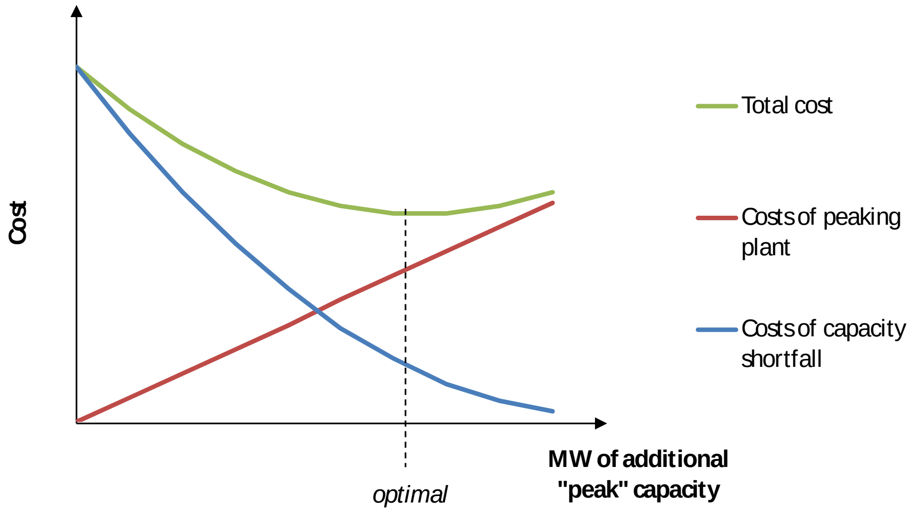
Figure 2: Illustrative cost of capacity shortfall curve



4.1.3 Reserve power stations (assumed to be open-cycle gas turbines providing firm MW capacity) are added and subtracted from the supply mix and the cost of capacity shortfall is recalculated.

4.1.4 The optimal level of capacity is found by calculating the total expected costs of reserve capacity and EUSE for varying levels of reserve capacity i.e., repeating the above steps for varying levels of reserve capacity. The trade-off between costs of reserve capacity and capacity shortfall is illustrated in Figure 3.

Figure 3: Illustration of cost trade-off



4.1.5 The optimal capacity margin is that which achieves the minimum combined cost of reserve energy and EUSE. Having established the optimal capacity margin it is then possible to determine the optimal EUSE and LOLE.

4.1.6 Input assumptions are not discussed here; a detailed discussion of the assumptions is contained in Appendix 2. However, it is worth noting that the LDC convolution approach was tested across a range of future supply scenarios, as summarised in Table 2.

Table 2: Base case scenarios

Scenario	Description
Base ’08	2008 forecast demand 2008 capacity mix
Wind ’08	2008 forecast demand 2008 capacity mix with 400MW of additional wind assumed correlated with Tararua,
Base ’12	2012 forecast demand 2008 capacity mix with additional firm capacity (eg geothermal) to meet demand growth
Wind ’12	2012 forecast demand 2008 capacity mix with 400MW of additional wind assumed correlated with Tararua

4.2 Modelling results

4.2.1 The modelling analysis has three components:

(a) Developing capacity shortfall curves using the LDC convolution approach;

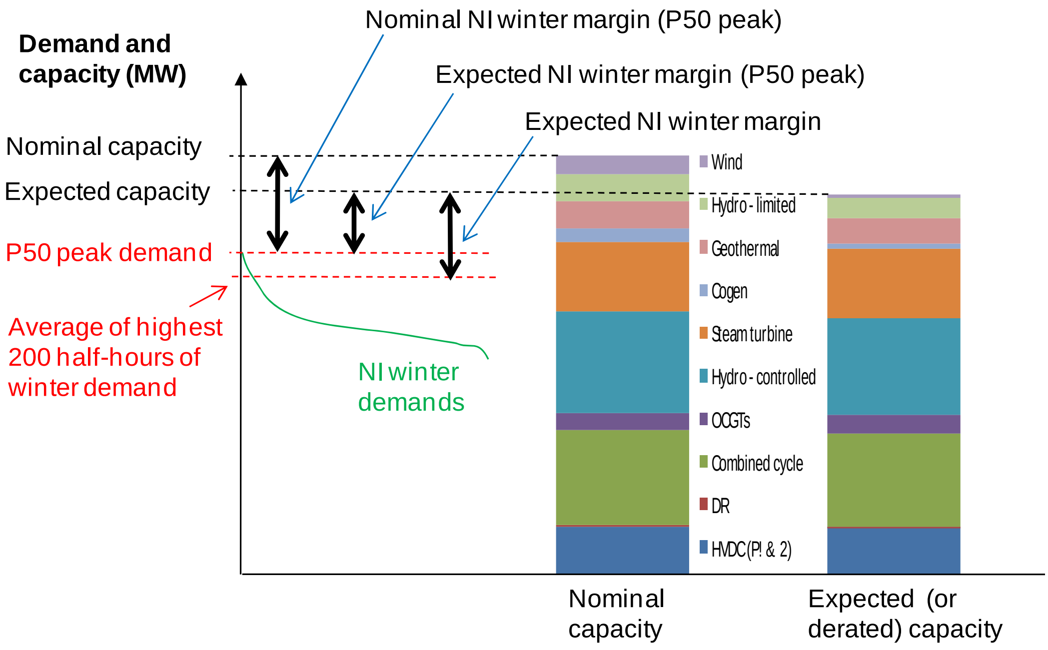
(b) Finding the optimal trade-off between costs of capacity and capacity shortfalls for the capacity shortfall curves and calculating or expressing the level of capacity adequacy at that point.

4.2.2 As has been discussed, capacity adequacy is typically expressed in terms of a MW capacity margin, the level of EUSE, LOLE or LOLP. The analysis produces standards defined in all these forms – some are based on inputs to the analysis (MW margin) and some on the outputs (EUSE, LOLE).

4.2.3 Like the winter <u>energy</u> margin, a simple winter MW capacity margin is simple to communicate and to calculate from input assumptions. For this reason it is more useful than LOLP or EUSE measures which can't be simply derived from the input assumptions.

4.2.4 A potential problem with the optimal capacity margin is that (depending on how it is defined) it can vary from year to year depending on demand and supply mix. To investigate this, the Commission considered several variants of MW margins (employing different measures of supply capacity and demand) as illustrated in Figure 1. The aim was to choose that variant which remained stable over the range of different situations expected to 2012.

Figure 4: Illustrative margin calculations

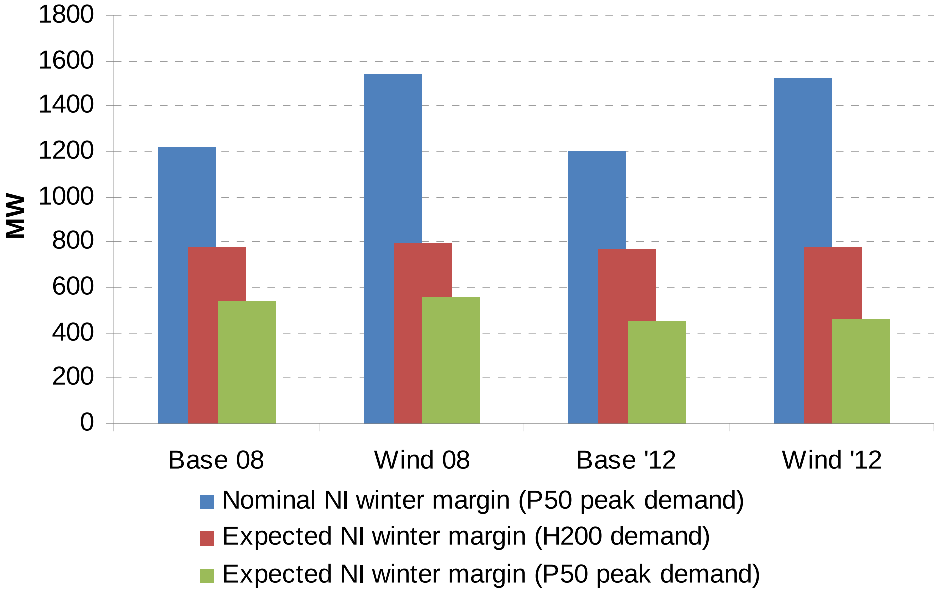


4.2.5 Because approximately half the North Island capacity is supplied by large thermal units (250MW or more), the system is susceptible to capacity shortfalls at times of high demand rather than just the "peak" demand. To this end, a reference demand was defined as the average of the highest 200 half-hours of forecast winter daytime demand (referred to as H200 demand).

4.2.6 The form of the standard was considered in the submissions to the May 2008 consultation paper (see Appendix 1). Views on the appropriate form for the capacity adequacy standard (MW margin, LOLP or EUSE) were mixed, and no particular view predominated.

4.2.7 MW margins for the four supply scenarios which reflected different mixes of new base-load and intermittent supply. The optimal MW margins for each scenario are illustrated in Figure 5.

Figure 5: Optimal capacity margins (MW)



4.2.8 Of the three margin variants measured, the Commission has selected the "North Island winter MW margin" as the form of the capacity adequacy standard. This yields a very stable "optimal" solution across the scenarios in the order of 780 ±10 MW. As noted, stability is a useful attribute in that it is far easier to communicate changes to supply and demand over time relative to a constant margin. Although the other variants are not as stable, they are useful for comparative purposes (e.g. most international margins are based on nominal installed capacity at a P50 peak demand).

4.2.9 Note that the output-based measures (see Appendix 3) are also stable across the scenarios and indicate levels that are:

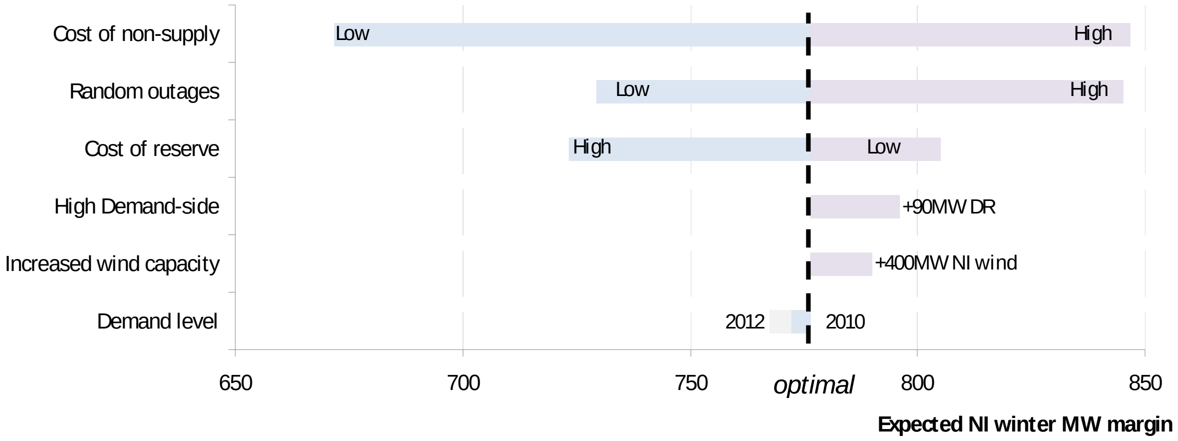
(a) Broadly consistent with overseas standards (for example EUSE of 2-3 hours or 0.002% annual demand, as outlined in Appendix 3); and

(b) Broadly consistent with the National Winter Group 2008 (NWG) analysis. The June NWG update indicated a surplus above the operational standard of 240MW. Although not intended as a metric for assessing day to day adequacy, the assessment of 2008 using the capacity adequacy standard discussed here yields a surplus of 216MW above the 780MW standard. This comparison is discussed in Appendix 3.

4.2.10 Having decided on the form of expression of the standard (i.e., the expression of capacity adequacy via a MW margin), a level of the standard must also be determined.

4.2.11 Figure 6 below shows the optimal level of the margin for a range of different assumptions for the cost of capacity shortfall, the cost of new peaking capacity, random outage rate, demand level and plant mix (see Appendix 3 for additional discussion).

Figure 6: MW margin sensitivities (2008 base)



4.2.12 As can be seen the optimal MW margin is very sensitive to the capacity shortfall cost assumption and is less sensitive to other assumptions such as the random outage rate and cost of reserve capacity.

4.2.13 Defining the level of the standard needs to take into account how the standard will be used in practice and the inevitable indirect costs of the Commission intervening in the market should the forecast standard be breached. For example, to avoid the Commission being forced to intervene (possibly earlier than is desirable), a standard set to act as a “hard” trigger for the purchase of reserve capacity might need to be set at a lower level than a standard set to act a “soft” trigger. A “hard” trigger would immediately initiate a process to purchase reserve capacity, while a “soft” trigger would initiate a process for the Commission to consider whether it was warranted to purchase reserve capacity.

4.2.14 On balance, the Commission has decided to define the standard as 780MW. The Security of Supply Policy has been worded such that assessments against the margin will be used as a “soft” trigger. This is consistent with the approach the Commission has adopted for reserve energy and appears to be favoured by at least some stakeholders, several of whom expressed a preference for an “orange light” approach which does not force the Commission to procure reserve capacity if the standard is breached and provides for more time for the market to respond.

4.2.15 The May 2008 consultation paper observed (as did some submitters) that reserve energy and reserve capacity will be somewhat interlinked. Adding reserve energy to the system would have the effect of adding reserve capacity (since there will be MW associated with any reserve energy) and adding reserve capacity would have the effect of adding reserve energy (since there will be MWh associated with any reserve capacity). The materiality of these effects will depend on the characteristics of any reserve energy or reserve capacity additions that are contemplated.

4.2.16 The Security of Supply Policy contemplates that these effects will be considered when the Commission is evaluating reserve energy (and reserve capacity) procurement options.

5. Discussion and Conclusions

5.1.1 Capacity adequacy standards can be defined in a variety of ways, but typically are defined as either a MW capacity margin, a level of expected unserved energy (EUSE) or a loss of load expectations (LOLE or LOLP).

5.1.2 The options for determining a capacity adequacy standard range from assessments of historical performance of the system, to direct estimation of the adequacy measures and the application of criteria or judgement to the outcomes. Internationally, standards are commonly expressed as EUSE or LOLE, although other measures are often monitored. LOLE standards are typically around 3 hours per annum and EUSE is typically around .002%.

5.1.3 This paper describes the application of an economic approach, trading off the costs of capacity shortfalls against the costs of adding reserve capacity. Techniques for performing this assessment differ principally in the handling of inter-temporal linkages and the degree of detail around the causes and consequences of capacity shortfalls. An LDC convolution approach was applied which captures the interaction between supply and demand on a probabilistic basis.

5.1.4 The results indicate that a North Island margin expressed in MW terms is a potentially stable measure of capacity adequacy for the period through to 2012 (at least). The analysis focussed on North Island adequacy, though explicitly accounted for the interaction of South Island supply/demand and northward transmission capability. The MW margins were calculated as the difference between expected winter supply and transmission and a measure of winter demand.

5.1.5 Because approximately half the North Island capacity is supplied by large thermal units (250MW or more), the system is susceptible to capacity shortfalls at times of high demand rather than just the “peak” demand. To this end, the reference demand was defined as the average of the highest 200 half-hours of forecast winter daytime demand.

5.1.6 Base case results suggest an expected North Island winter margin of 780MW. Sensitivity analysis resulted in variation of +/- 70 MW for variation in either costs of capacity shortfalls, costs of reserve capacity, and peak availability. This 780MW margin is broadly consistent with the heuristic standard adopted by the National Winter Group in their assessment of peak adequacy for winter 2008, although is defined differently. It is also broadly consistent with international LOLP and EUSE standards.

Appendices

Appendix 1 Discussion of submissions

1.1.1 A consultation paper was issued on 13 May 2008 and outlined and implemented the proposed methodology for deriving a capacity adequacy standard.

1.1.2 The key conclusions in that paper were that:

(a) Using a “load duration curve (LDC) convolution” approach is suitable for measuring the depth and duration of capacity shortfalls;

(b) An economic approach should be used to develop a standard on the basis of trading off the costs of capacity shortfall against the costs of reserve capacity;

(c) A standard should be defined on the basis of an “expected North Island winter MW margin” (rather than loss of load probability of expected unserved energy);

(d) The level of the standard was likely to be approximately 710MW (+/- 70MW);

(e) Further work on assessing chronological issues was required to confirm the approximations made in the analytical approach.

1.1.3 A workshop was held with interested parties on 6 June 2008.

1.1.4 Submissions were received from Mighty River Power, Genesis Energy, Meridian Energy, Contact Energy, Transpower, PowerCo, Vector, and MEUG.

1.1.5 This appendix summarises the key points from these submissions and, where relevant, discussion from the 6 June 2008 workshop.

1.1.6 The content of this explanatory paper has been updated to, where possible, address issues raised in submissions.

Summary

1.1.7 Seven questions were included in the consultation paper and focussed on the economic approach used to develop the standard (trading off costs of demand restraint against costs of reserve capacity), the assumptions used, the modelling methodology, and the form of the standard (North Island winter MW margin). For the most part, there was little disagreement with the approach and assumptions taken, with submissions providing useful suggestions about aspects of the methodology and assumptions that might benefit from additional clarification.

1.1.8 Although not a specific consultation question, a common issue raised by submitters was the intended use of the standard. The consultation paper stated that its focus was developing the standard rather than its implementation and how the Commission intended to use it. That said, the consultation paper did indicate that the Commission would contemplate an approach to capacity adequacy that mirrored that taken for monitoring and triggering the procurement of reserve energy.

1.1.9 There was general support for a capacity standard for monitoring and information as there is no forecast at present, and the National Winter Group analysis only caters for the next winter. However, submissions raised a number of issues relating to how the standard may be used:

(a) Uncertainty about the “purpose” of the standard;

(b) Concern about the possibility of unjustified intervention with large impacts from use of a new/untested/hastily developed standard (including Meridian’s concern that a capacity adequacy standard could result in a departure from the energy only price and will be detrimental to improving liquidity and hedge arrangements in NZ);

(c) Concern about rigidity of the standard (red light vs. amber light);

(d) Concern about interface between the standard and operational assessments/ monitoring;

(e) Desire to have additional consultation/industry involvement on further developments, and flexibility to make changes/learn as more data available; and

(f) There was some confusion around impacts of dry year risk and interaction with reserve energy monitoring/procurement.

1.1.10 These issues have been addressed to the extent possible in the additional analytical work, associated discussion, and amendments to the Security of Supply policy. Due to the technical nature of many of the issues raised, discussion with individual submitters would be the most efficient means for communicating/resolving outstanding issues.

Consultation questions

Q1 Do you agree with the recommended approach of using an economic approach for establishing a security standard?

1.1.11 Submissions indicated general agreement with the use of economic trade-off. Agreement was indicated by Genesis, Contact, Meridian, Vector, Transpower, PowerCo, and MEUG. Vector asserted that the approach doesn’t reflect year-on-year risks, but this is not the case, and it appears there was some confusion with the approach taken. Vector suggested that change of name to ”Generation Capacity Adequacy Standard” be considered.

Q2 Do you agree that the approach developed by trading off the cost of demand restraint against the cost of reserve energy is an appropriate means of implementing an economic approach?

1.1.12 Genesis, Contact, Meridian, Vector, PowerCo, MEUG agreed that the LDC convolution approach is appropriate.

1.1.13 There was support for chronological work to support the assumptions. Useful suggestions were made about aspects of methodology which would benefit from further clarification.

Q3 Do you agree with the assumptions used to cost peak supply plant?

1.1.14 Contact agreed, while other submitters had no firm view.

1.1.15 Genesis commented that OCGTs don't come in 1MW increments and that they are not the only/most likely way of improving capacity adequacy.

Q4 Do you agree with the assumptions used to cost capacity shortfalls?

1.1.16 Genesis, Contact, and Vector agreed, while other submitters had no firm view.

1.1.17 Genesis suggested that the assumptions may under-estimate the potential for voluntary restraint during periods of tight capacity. PowerCo suggested that the Commission should research the costs of non-supply.

Q5 Do you agree with the supply assumptions outlined in Appendix 2?

1.1.18 Contact agreed, Meridian/Vector disagreed, while other submitters had no firm view.

1.1.19 The following comments were made:

(a) Thermal forced outage data could be investigated in more detail (Contact);

(b) Additional wind data would assist in validating assumptions (Contact, MEUG);

(c) Forced outage rates should be higher (Vector);

(d) Additional extreme and low probability contingencies could be considered (Vector);

(e) Multiple conservative assumptions used (Meridian); and

(f) Comparison with historic data to ensure market realities captured and assumptions accurate (Meridian, Genesis).

1.1.20 Many of these issues have been addressed via the additional review of assumptions and chronological modelling undertaken since the consultation paper was issued. In particular, forced outage rates have been reviewed (and increased slightly for some thermal plant). A large proportion of the input assumptions are based on historic generation performance.

1.1.21 There was some confusion about how generation capacity is modelled when determining the standard, and how it is counted in the "margin" calculations. This could be clarified.

Q6 Do you agree with the demand assumptions outlined in Appendix 2?

1.1.22 Contact and MEUG agreed, while other submitters had no fixed view.

1.1.23 The use of the "average of the highest 200 half-hours" as the baseline demand was queried in terms of overall rational and its relationship to operational assessments (e.g., NWG assessment against peak demand).

Q7 Do you agree that the most appropriate expression of the standard for measuring capacity adequacy over the medium-term is the expected North Island winter MW margin (as defined in the report)?

1.1.24 Genesis, Contact and MEUG agreed.

1.1.25 Submitters had mixed views on whether the margin should be expressed as a MW margin. Views ranged from "easier to understand than EUSE/LOLP" to "EUSE/LOLP a better indicator of possibility of outages". It was suggested that there would be merit in using LOLP/EUSE when explaining the margin and for comparison with overseas.

1.1.26 As indicated in the Transpower submission, it will be important to reinforce the linkage between the (long-term) capacity adequacy standard and operational assessments.

Appendix 2 Summary of Assumptions

2.1 Cost of reserve capacity

2.1.1 For the base case, annualised cost of reserve MW was estimated as that of an open cycle gas turbine (OCGT) unit at $124/kW/yr. This is derived from

(a) $24/kW/yr fixed O&M costs; and

(b) $100/kW/yr of annualised capital costs (based on 25 year life and 9% nominal post-tax WACC).

2.1.2 This is based on a report prepared by PB Power for the Electricity Commission dated April 2008[3]. This provided a costing for a 50 to 100MW peaking plant with around 2% capacity factor and around 30 starts per annum operating on gas or liquid fuels at a greenfields plant close to existing infrastructure. Their recommended capital cost estimates including an allowance for North Island location specific costs are $1,008 (100MW Industrial gas turbine) to $1,514 $NZ/kW (50MW Aero derivative Gas Turbine).

2.1.3 Contact Energy's reported cost of $1,250/kW for its proposed 200MW gas fired OCGT at Stratford. Their recommended fixed operating cost is around $24/kW/yr for this mode of operation (including $10/kW/yr for fuel management). The variable operating costs are estimated to be around $7 to $12/MWh, on top of the cost of gas or liquid fuel (greater than $300/MWh).

2.1.4 PB Power note that cost estimates are subject to significant uncertainty with 20 to 30% price rises having occurred during the last 18 months.

2.1.5 The base case annualised cost is derived from the 100MW industrial gas turbine cost. For sensitivity testing, a range from $100/kW/yr to $180/kW/yr has been used[4]

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[3] See "Cost Estimates for Thermal Peaking Plant", Draft report for the Electricity Commission, PB Power, April 2008.

[4] In addition to the variation in the estimated costs of a peaking plant there is a conceptual issue regarding the effective cost of additional peaking plant. This arises from an interaction with the "energy" shortages. An additional MW of OCGT may contribute to both "energy" and "peak" security. For this reason the effective incremental cost for "peak" capacity may be less than the full cost of a new OCGT plant. This is ignored for this analysis as it is considering peak standards only. The issue should be considered in the context of policy options in the event that the economic capacity margin was breached. It is important that the threshold for policy response recognises that intervention in the market may have additional costs not reflected in this analysis.

2.2 Cost of capacity shortfall

2.2.1 The analysis requires some key assumptions concerning the cost of demand restraint and/or outages. In contrast to energy demand restraint, there is very little warning of the need for restraint over the shorter time frame considered when considering capacity adequacy. This limits the expected response from the market and increases the cost of outages considerably.

2.2.2 A capacity shortfall is identified when there is insufficient capacity, or Interruptible Load (IL), available to meet “normal” peak period demand plus “normal” instantaneous and frequency regulation reserve.

2.2.3 Whenever there is a capacity shortfall voluntary and/or involuntary demand restraint is required[5].

2.2.4 The voluntary restraint can occur in response to market participants forecasting a risk of high prices or in response to System Operator warnings. It can also be contracted demand-side response.

2.2.5 Involuntary restraint (or outages) can occur either from Automatic Under Frequency Load Shedding (AUFLS) during a system contingency (tripping of a large generation unit or transmission line) or from pre-contingent load shedding instructed by the System Operator.

Involuntary load shedding

2.2.6 The New Zealand electricity system has two levels of protection against contingencies (the sudden loss major generation units or transmission lines). The first level involves the system operator contracting with generators or loads for instantaneous reserves (IR) capable of responding within seconds of a contingency. The first level is designed to cover single large contingencies (the loss of the largest generation unit or transmission link).

2.2.7 The second level of protection involves the use of Automatic Under Frequency Load Shedding (AUFLS) relays. These automatically disconnect one or two 16% blocks of load if there is double contingency (the simultaneous loss of two or more large units or links).

2.2.8 The purpose of these levels of protection is to avoid “system collapse”. This can occur if the frequency falls so much that generation units could become unstable and must be disconnected. In this case the entire North or South Island supply system will fail and it may take several hours to restore supply. The social and

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[5] Demand restraint is measured relative to demand expected at normal peak period pricing (i.e. less than $200/MWh). We only consider demand response over and above “normal” peak management (e.g. via ripple control of water heating load).

personal cost of “system collapse” is very high as hospitals, central business districts, computer systems, transport systems, factories etc are all affected. It makes sense to disconnect just a portion of the less sensitive loads (e.g. residential) to avoid system collapse in a contingency.

2.2.9 Normally the System Operator will procure sufficient instantaneous reserve in addition to forecast demand to ensure that single large contingent events can be covered without involuntary load shedding[6].

2.2.10 However if there is insufficient capacity available and offered to the market then the System Operator will operate the system in an “emergency secure state” with less than normal instantaneous reserve. The system is still secure, in that it is not likely to collapse, but there is a risk of automatic load shedding if there is a sudden loss of a large generation unit or transmission line (e.g. a CCGT unit or the HVDC). The extent of the risk will depend on the shortfall in instantaneous reserve.

2.2.11 Normally around 400MW of instantaneous reserve is procured at peak times when the CCGT units are operating at full capacity. If there is a shortfall of 100MW, then the first of the 2 AUFLS blocks would be shed if there is a sudden loss of greater than around 300-400MW of generation or HVDC transfer. If the capacity shortfall is greater than 100MW then a smaller contingency (such as the loss of around 200MW unit) could result in the operation of AUFLS. There are twice as many generation units above 200MW, than 300MW, and hence the risk of AUFLS operating increases as the capacity shortfall increases.

2.2.12 The probability of a sudden loss of a significant generator or HVDC on the NZ system is relatively low. Historically there have been around 10-20 system events (greater than 200MW[7]) per annum, but only 2-10 large system events (greater than 300MW[8]). Very large system events (greater than 800MW) have only occurred a few times over the last 20 years (typically being the loss of either both poles of the HVDC contingency, or a single pole of the HVDC combined with a large thermal unit).

2.2.13 Conservative estimates of system event risk probabilities are as follows:

(a) system events (around 150-250MW) = 0.6% per half hour trading period (an event in up to 100 periods per annum);

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[6] In a normal secure state the System Operator will procure sufficient instantaneous reserves to avoid the frequency falling below 48Hz with the lost of a single generating unit or pole on the HVDC. This avoids tripping of the AUFLS relays. If necessary the system operator will also procure additional reserves to avoid the frequency falling below 47 Hz with a bi-pole trip. This effectively covers some generator double contingencies (e.g. a simultaneous trip of two CCGT units). This utilises the AUFLS, but avoids system collapse.

[7] These typically cause the system frequency to fall below 49.5 Hz.

[8] These typically cause the system frequency to fall below 49.0Hz.

(b) large system events (around 300-400MW) = 0.1% per trading period (an event in up to 20 periods per annum); and

(c) very large system events (greater than 800MW) = 0.01% per trading period (1 very large event per annum).

2.2.14 The expected level of automatic under frequency load shedding depends on the the likelihood of these events risks and on the size of the AUFLS block or blocks tripped and the time to restore load.

2.2.15 When all this is taken into account the probability weighted average amount of actual load shedding is conservatively estimated to be around 2MW (or 2%) for the first 100MW of capacity shortfall, rising to up to around 5MW (or 5%) for the second 100MW of capacity shortfall (greater than 100MW but less than 200MW). The estimated expected capacity shortage cost is of the order of $1000 to $6,600/MWh[9].

2.2.16 It is more difficult to estimate the risks[10] and costs for capacity shortfalls beyond 200MW and less than 400MW so a very conservative 20MW of actual load shedding (or 20%) per 100MW of capacity shortfall is assumed. This implies an expected capacity shortfall cost of $6,000 to $22,000/MWh.

2.2.17 If the capacity shortfall is greater than the total instantaneous reserve then the System Operator will instruct distributors to shed load to maintain an emergency secure state. The average cost of this is likely to be in the range $11,000 to $100,000/MWh depending on the depth of the cuts required.

2.2.18 The Commission currently uses a load weighted average of NZ$22,000/MWh for transmission planning studies[11]. This was established in 2004 and is about to be reviewed by the Commission.

2.2.19 International estimates for load weighted average cost of transmission cuts are typically greater than this, for example VenCorp in Victoria has recently updated its estimate from A$30,000 to A$48,000/MWh (NZ$56,000) [12]. However distributors

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[9] Note that the expected capacity shortage cost here is measured relative to the level of capacity shortfall, not relative to the actual cost of AUFLS when it occurs.

[10] As the safety margin decreases there is a risk of cascade or flow on effects resulting from very rapid falls in frequency. These are difficult to quantify and so a very conservative approach is taken.

[11] The value of unserved energy is currently set at $20,000/MWh (Dec 2004 dollars) for the NZ Grid Investment Test. The Grid investment Test required sensitivities of $10,000 and $30,000/MWh to be tested. The value was recommended by Frontier Economics in June 2004 and was the subject of consultation in 2004 and 2005. The Commission received a wide range of views but the proposed $20,000/MWh value was not strongly contested and a CRA report provided by Meridian suggested that the $20,000/MWh figure was a good starting point given previous NZ and overseas work. The Centre for Advanced Engineering was commissioned to update their 1992 assessment and derived a VoLL for NZ of $20,950/MWh on the basis of a VENCorp study adjusted for New Zealand electricity use percentages. Castalia reviewed the value in August 2006 for Transpower and suggested a range of $22,000 to $48,000/MWh with a central value of $32,000/MWh.

[12] See “Estimation of the Economically Optimal Reliability Standard for the National Electricity Market” MMA , June 2006, and “Assessment of the Value of Supply Reliability (VSR), CRA, August 2008.

should be able to limit cuts to the most expensive areas (such as central business districts) for the first 400MW (8%) of instructed load shedding, so the cost will be less than the load weighted average.

2.2.20 For this study it is conservatively assumed that the marginal cost increases progressively from around $20,000/MWh towards $100,000/MWh as the depth of instructed load shedding increases.

Contracted demand-side response

2.2.21 In principle, voluntary demand side response can be contracted. An example of this is the Demand-side Participation Pilot that is being trialled by Transpower as a potential alternative to transmission investment in the Upper South Island.

2.2.22 The Transpower pilot study is useful in that it indicates the potential for demand-side response. In 2007, Transpower called for tenders for demand-side response in the Upper South Island. They received offers of 50MW (around 5% of load) with prices in the range $700 to $12,000/MWh as shown below.

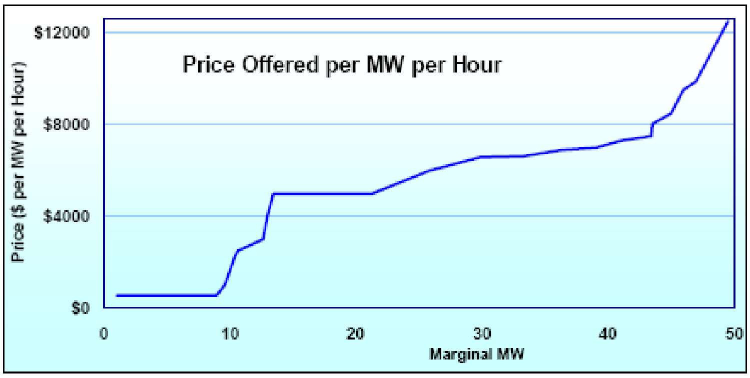


Figure 4: Cost per MW per hour for each additional MW

2.2.23 They selected 14 offers (4 participants) with a total of 14MW or around 1.5% of the load in the area. This was split 50% industrial, 20% cold store and 30% generation and had offered prices from around $700 to $5,000/MWh. The demand side responded with a reliability of around 75% during the trial.

2.2.24 While there is no specific plan to contract for demand-side response for energy adequacy at this time, the pilot does quite clearly indicate the potential for the demand side to respond to price signals in the range $1,000 to $5,000/MWh.

Spontaneous demand-side response

2.2.25 This demand-side response can occur spontaneously if customers are exposed to spot prices and they have an expectation that ex-post prices will rise to $1,000 to $5,000/MWh during a capacity shortfall. Under current market arrangements there is a significant risk that ex-post prices will not reach these levels in this event and so the spontaneous market response is limited.

2.2.26 If the market mechanisms were improved to provide more information relating to the risk of capacity shortfalls and more predictable pricing in these events then significantly more spontaneous demand side response might be expected. This analysis only assumes a nominal 10MW (0.2%) spontaneous response to expected shortfalls and system operator warnings.

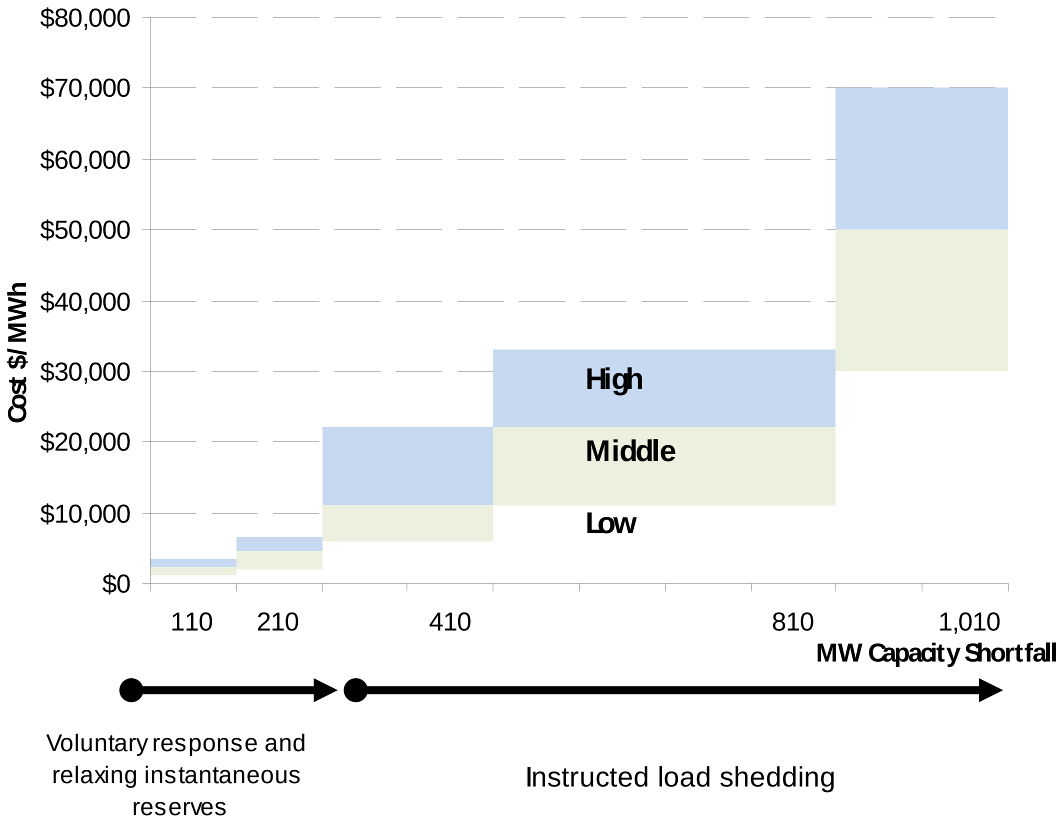
Summary

2.2.27 Table 3 and Figure 7 summarise the cost and quantity assumptions used in this analysis. The “mid” cost curve is used for the base case analysis, with the low and high curves treated as sensitivities.

Table 3: Cost of shortfall assumptions ($/MWh)

Cost of Capacity Shortfalls						
	MW Shortfall		Marginal Cost $/MWh			
	Step	Total	Low	Mid	High	Basis of cost estimate
Demand side 1	10	10	$500	$1,100	$1,200	Voluntary low cost response to expected high price eg. extended ripple control
Emergency Secure 1	100	110	$1,000	$2,200	$3,300	Risk of AUFLS with 100MW IR shortfall
Emergency Secure 2	100	210	$2,000	$4,400	$6,600	Risk of AUFLS with 200MW IR shortfall
Demand side 2	-	210	$4,000	$8,800	$11,000	Voluntary high cost response to expected high price eg. Load management
Emergency Secure 3	200	410	$6,000	$11,000	$22,000	Conservative higher risk of AUFLS with 300-400MW IR shortfall
Load Shedding 1	400	810	$11,000	$22,000	$33,000	Cost of shallow instructed load shedding (to 10%)
Load Shedding 2	400	1,210	$30,000	$50,000	$70,000	Cost of deeper instructed load shedding
Load Shedding 3	2,000	3,210	$50,000	$75,000	$100,000	Cost of very deep load shedding including high cost sectors such as CBDs

Figure 7: Cost of capacity shortfall curves



2.3 Forced outage rate assumptions

2.3.1 Forced outage rate assumptions used in the earlier consultation (Huntly 3%, New Plymouth 4.5%, CCGTs 2% and hydro 2%) were based on those derived for the Needs Assessment in October 2006. This was based on North America Reliability Council (NERC) statistics and discussions with generators. Additional data available from NERC was reviewed and compared with forced outage rate assumptions used in Australia and other New Zealand studies in order to develop a set of new forced outage values (applicable to analysis of capacity and energy).

2.3.2 NERC derive a range of different measures of forced outage rate, the most relevant for this exercise is the equivalent forced outage rate (EFOR) which accounts for both full and partial outages. This measure can be biased upward for units with low capacity factor operation, the NERC EFORd measure has been derived to adjust for this bias. The following table summarises the different measures for the different countries.

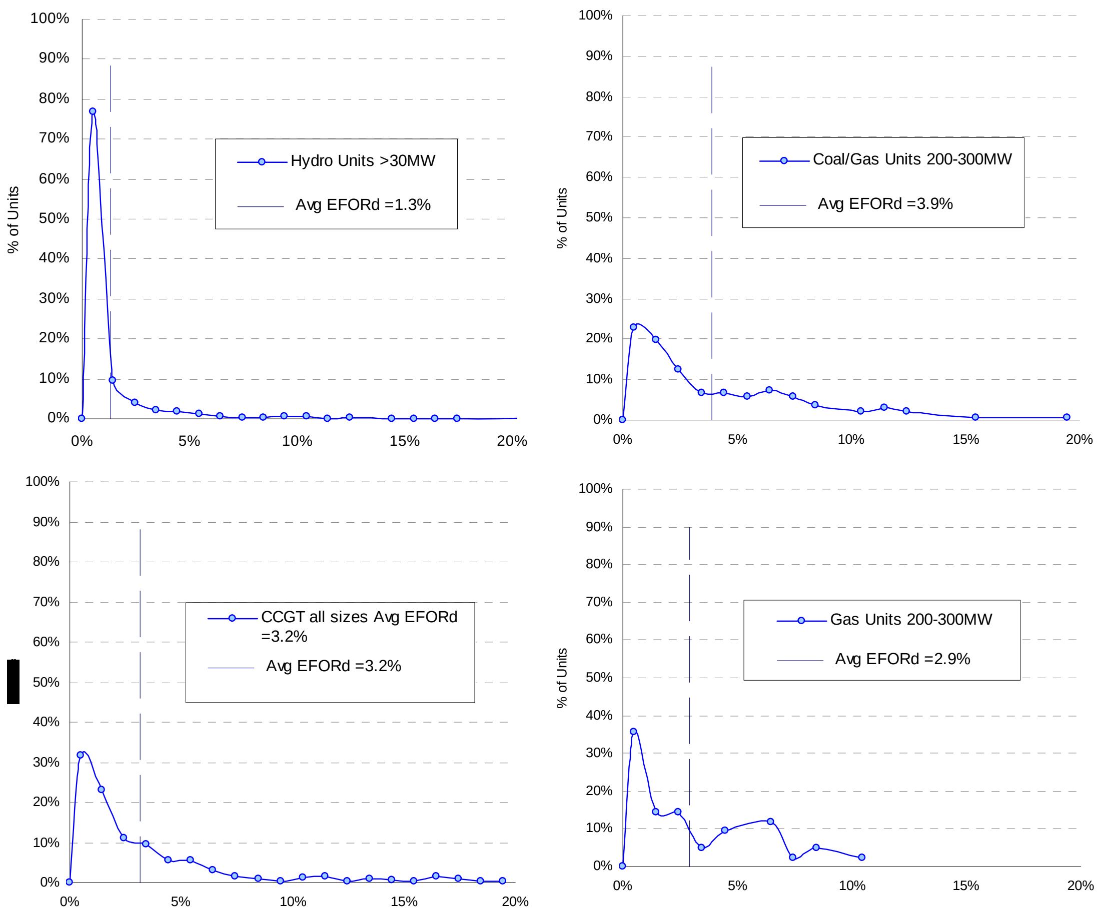
Table 4: Alternative Forced Outage Rate Measures

	Hydro >30MW	CCGT all sizes	Coal/Gas 200-300MW	Gas 200-300MW	OCGTs All sizes
NERC - North America Reliability Council Stats 2002-2006					
Number of unit years	644	461	136	41	553
FOR	1.8%	4.0%	4.8%	6.1%	5.7%
EFOR	1.9%	5.0%	6.6%	8.0%	5.8%
EFORd	1.3%	3.2%	3.9%	2.9%	2.0%
NEMMCO - Australian - 2008 Annual National Transmission Statement					
FOR	3.3%	4.1%	2.9%	2.0%	22.0%
EFOR	4.1%	4.5%	4.2%	2.4%	22.0%
Snowy FOR (2006)	1.8%				
Tasmania FOR (2006)	1.3%				
ROAM Consulting NZ 2006 - Reliability of Supply into Auckland June 2006					
FOR	1.5%	5.0%	4.0%	4.0%	2.0%
MMA HVDC Study Feb 2008					
FOR		5.0%	3.0%		2.0%

ROAM Consulting (2006) used 5% FOR for CCGTs in NZ and 4% for Huntly and 1.5% for Hydro
MMA (2008) used 3% FOR for Huntly, 5% for CCGT, 2% for Whirinaki

2.3.3 Figure 8 shows the distribution of EFORd for units similar to our hydro and CCGT units and Huntly. Note that the mean values calculated exclude very old or very unreliable units with forced outage rates greater than around 20%.

Figure 8: Distribution of EFORd: NERC statistics 2002 - 2006



2.3.4 The data above suggests that the earlier forced outage rate assumed for Huntly (3%) is reasonable, but that the 2% previously assumed for the CCGTs may be a bit low compared with NERC and Australian statistics. Discussions with thermal generators in New Zealand indicate that forced outage rates have typically been better than 2% over the last few years. However the true mean needs to account for more significant outages that can occur occasionally but may not be observed in a small sample.

2.3.5 The 2% rate assumed for hydro units is on the high side compared with NERC and the most comparable Australia data (Snowy and Hydro Tasmania). However, due to due to the nature of small and frequent scheduled outages of hydro units throughout the year, a 2% level was maintained.

2.3.6 There is considerable variation in forced outage rate for open cycle gas turbines. The NERC data adjusted for low capacity factor operation bias is round 2%. Australia uses 22%, but this measure may also be biased and probably includes old unreliable units. The only OCGT in New Zealand is Whirinaki, which is new and has very good start reliability.

2.3.7 On the basis of this review it is recommended that the following forced outage rates be used:

Table 5: Recommended Forced Outage Rate Assumptions

	Hydro	CCGTs	Huntly	Other thermal
Low Assumption	1.0%	2.0%	2.0%	2.0%
Base Assumption	2.0%	3.0%	3.0%	3.0%
High Assumption	2.0%	5.0%	5.0%	5.0%

2.4 Supply assumptions

2.4.1 Existing supply assumptions by island and fuel type are summarised in Table 6. The expected winter MW reflects deratings for forced outage rates, scheduled winter outages, and deratings from the chronological modelling discussed in Appendix 4.

Table 6: Summary of existing supply

Plant categories	**Nominal MW**	**Expected MW for winter margin calculation**	**Comment**
Thermal	2,502 (NI)	2,427 (NI)	Forced outage rates applied to nominal capacity adjusted for scheduled outages.
Controlled hydro	1,556 (NI) 3,256 (SI)	1,428 (NI) 3,103 (SI)	Nominal capacity and forced outage rates applied to units. Adjustment made on scheme by scheme basis for scheduled outages and chronological effects.
Uncontrolled hydro	190 (NI) 44 (SI)	100 (NI) 23 (SI)	Expected MW based on distribution of aggregate historic output at winter peak.
Cogeneration	164 (NI)	90 (NI)	Expected MW based on distribution of aggregate historic output at winter peak.
Geothermal	419 (NI)	364 (NI)	Expected MW based on distribution of aggregate historic output at winter peak.
Wind	252 (NI) 58 (SI)	50 (NI) 12 (SI)	Simple derating of 80% used in margin calculations

Plant categories	**Nominal MW**	**Expected MW for winter margin calculation**	**Comment**
Interruptible load \	190 (NI)	166 (NI)	Expected MW based on distribution of aggregate historic offers consistent with definition of demand used for margin assessment.
Dermand response	10 (NI)	10 (NI)	Notional assumption about contracted demand response.
Totals	5,282 (NI) 3,358 (SI)	4,636 (NI) 3,137 (SI)	

Thermal plant

2.4.2 Assumptions about thermal plant are presented in the Table 7 below. The summer and winter distributions reflect the aggregate MW availability given scheduled and forced outage assumptions. Note that:

(a) Forced outage rates are those discussed earlier in this appendix, namely 3% for all thermal plant.

(b) A Huntly unit is assumed to be unavailable over the entire summer period, reflecting the effect of sequential scheduled Huntly unit outages over that period.

(c) TCC had its summer forced outage rate increased by 40%, which reflects the expected time over summer where e3p, OTA-B, and TCC are on scheduled outage (around 58 days per year on average). Applying the derating to a single unit reflects the sequential nature of the outages.

(d) Note that New Plymouth has not been included in the analysis.

2.4.3 The value of derated capacity used in the margin calculations are shown in the “CMV” column.

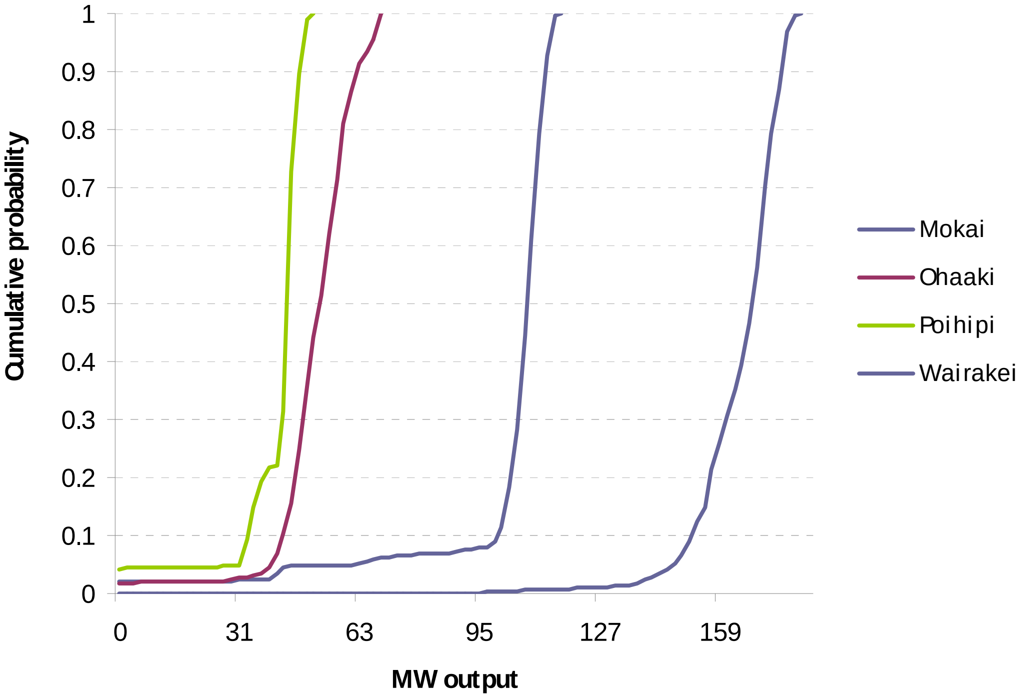
Table 7: Thermal assumptions

Unit name	Nominal capacity	Annual FOR	CMV
Huntly1-4	972	3%	943
HLY_5 (e3p)	400	3%	388
HLY_6 (p40)	45	3%	44
Otahuhu B	385	3%	373
Southdown	170	3%	165
Taranaki CC	375	3%	364
Whirinaki	155	3%	150
Total	2502		2427

Geothermal

2.4.4 Capacity factor curves have been modelled for Mokai, Ohaaki, Poihipi and Wairakei based on data over the period 2002-2007 (adjusted for capacity changes over that time). Figure 9 illustrates the winter distributions of historic aggregate geothermal output across the four epochs.

Figure 9 Geothermal output distributions (winter days epochs)



2.4.5 The value of expected capacity used in the margin calculations are shown in the "CMV" column.

Table 8: Geothermal assumptions

Unit name	**Max output**	**CMV**
Mokai	117	103
Ohaaki	70	53
Poihipi	51	42
Wairakei	181	166
Total geothermal	419	364

2.4.6 The capacity factor distributions for each plant are relative to maximum observed output. Maximum geothermal output is 419 MW, with an expected value over the winter peak of 364MW.

North Island hydro

2.4.7 North Island hydro output is modelling by a combination of “controllable” and “uncontrollable” plant. Consistent with the conclusions of the chronological modelling (Appendix 4), North Island hydro plant are categorised as either “controlled” or “uncontrolled”. These assumptions can be summarised as follows:

(a) Controlled plant includes all stations on the Waikato scheme, Tokaanu, the Waikaremoana scheme, Patea, and Matahina.

(b) Uncontrolled hydro plant includes Mangahao, Rangipo, Wheao, and Mangaio.

2.4.8 Note that the output from some hydro plant (e.g., Waipori and Highbank) is excluded as they have been netted off demand, consistent with the Commission’s approach to developing forecasts for Security of supply analyses.

2.4.9 Input assumptions used for North Island hydro plant are presented in Table 9. The MW value used for calculating the expected winter margin shown in the “CMV” column. For controlled plant, the CMV is nominal capacity derated for scheduled outages /chronological limits and a 2% forced outage rate. For uncontrolled plant, the CMV is the expected value of aggregate output over winter days.

Table 9: North Island hydro plant assumptions

Scheme	Nominal capacity	Derating for chronological limits (MW)	FOR	CMV
Waikato[13]	1063	60	2%	983
Tokaanu	240	20	2%	216
Waikaremoana	141		2%	138
Patea	32	5	2%	26
Matahina	80	13	2%	66
Total NI controlled hydro	1556			1428
Uncontrolled NI hydro	190			100

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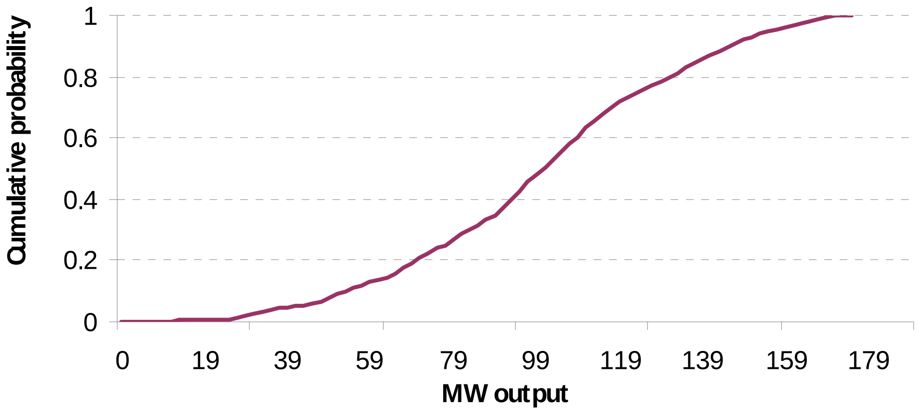
[13] A forced outage rate of 50% is applied to four of the ten Maraetai units over summer to reflect scheduled outages.

Figure 10: Distribution of uncontrolled North Island hydro plant (winter day epoch)



North Island cogeneration

2.4.10 Output of cogeneration plant are aggregated for the analysis. Plant included are Kaponga, Kinleith, Te Rapa, and Whareroa. Note that the output from some cogeneration plant (e.g., Glenbrook) is excluded as it is netted off demand, consistent with the Commission's approach to developing forecasts for Security of supply analyses.

2.4.11 The capacity factor distribution for aggregate output is illustrated in Figure 11 with Table 10 illustrating the nominal MW and CMV.

Figure 11: Distribution of aggregate North Island cogeneration (winter day epoch)

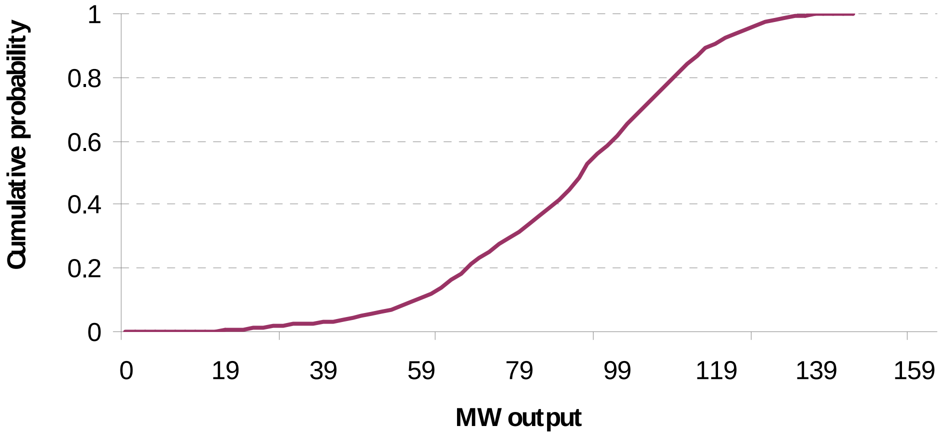


Table 10: North Island cogeneration assumptions

	Nominal MW	CMV
Aggregate cogeneration	164	90

South Island hydro

2.4.12 South Island hydro output is modelling by a combination of controllable and uncontrollable plant. These assumptions can be summarised as follows:

(a) Controlled hydro schemes are Waitaki, Manapouri, Clutha, Cobb and Coleridge, with a nominal capacity totalling 3256MW.

(b) Uncontrolled hydro schemes are Argyle, Opuha, Teviot, Kumara/Dillmans/Duffers, with a nominal capacity totalling 44MW.

2.4.13 Table 11 and Figure 12 summarise and illustrate the assumptions made for South Island hydro plant.

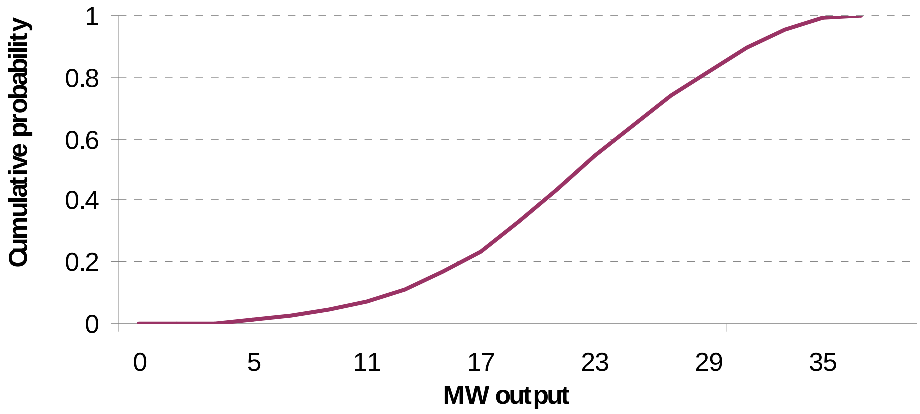
Table 11: South Island hydro plant assumptions

Scheme	Nominal MW	FOR	CMV
Waitaki scheme[14]	1633	2%	1512
Clutha scheme	740	2%	500
Manapouri	721	2%	707
Cobb	32	2%	31
Coleridge	40	2%	39
Total controlled hydro	3256		3103
Uncontrolled hydro	44	23	23

---

[14] A Benmore turbine is treated as being on permanent outage in summer and winter to reflect transformer limitations on Benmore station output. A 90% summer scheduled outage rate is applied to another Benmore unit, reflecting the average of rotating scheduled outages at the station. A 40% forced outage rate is applied to one of the Manapouri units over summer reflecting the combined effect of scheduled unit outages.

Figure 12: Distribution of uncontrolled South Island hydro plant (winter day epoch)



Wind

2.4.14 Distributions of aggregate wind output used for each island are illustrated in Figure 13.

(a) Aggregate North Island wind output is based on historical capacity factors for Tararua 1/2/3 and Te Apiti (also referred to as NI wind)[15].

(b) South island wind includes White Hill. Although there is some data available for White Hill (or SI wind) output, it was too limited for deriving representative distributions. In the absence of robust data, the distribution for NI wind was also applied to White Hill[16]. .

2.4.15 When calculating the expected winter margin, a factor equivalent to 20% of nominal capacity was used, representing a rounded value consistent with the effective capacity value of wind derived from the chronological analysis (Appendix 4).

Table 12: Wind supply assumptions

Unit name	Nominal MW	CMV
Aggregated North Island	251.8	50.4
Aggregate South Island	58	11.6

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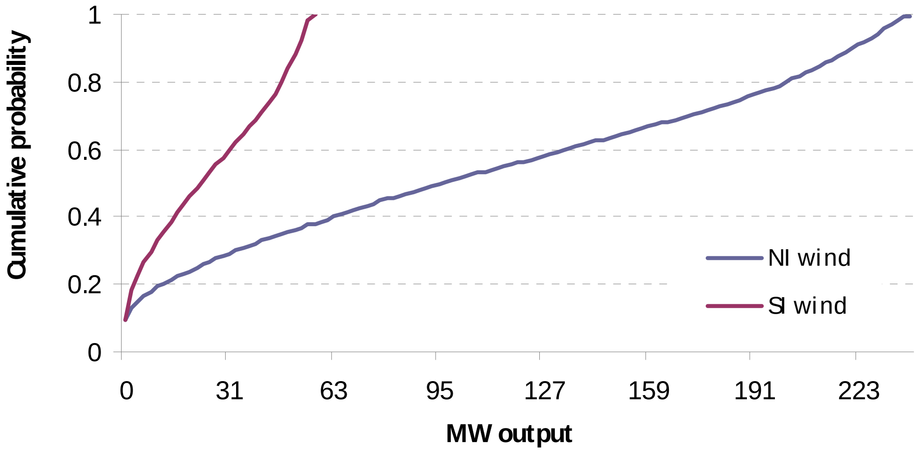
[15] Note that is a conservative approach. New wind farms in the North Island such as West Wind, are likely to be somewhat correlated with Tararua, but not completely.

[16] Although the same distribution was used for South Island wind it was assumed to be independent.

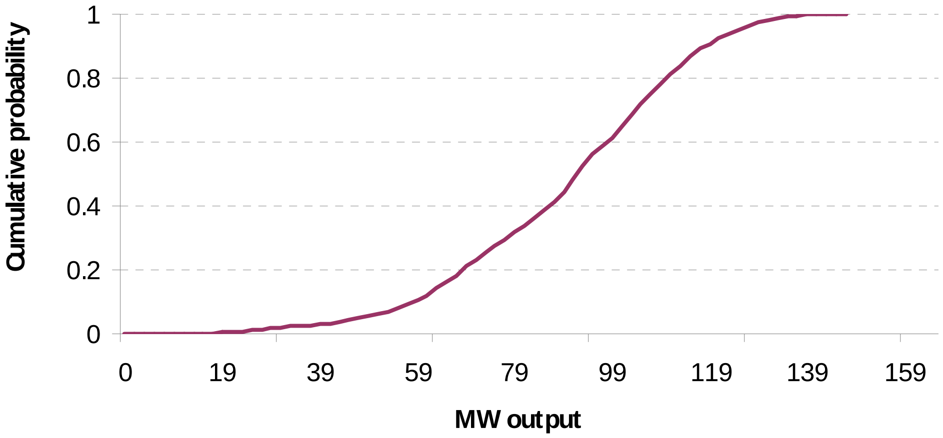
Figure 13: Distributions of aggregate wind farm output (winter day epoch)



Interruptible load

2.4.16 Supply of instantaneous reserve from interruptible load is treated as uncontrolled with a probability distribution with a mean and variance reflecting the historical offers available at times of peak demand. Note that there is a negative correlation between IL and demand, and hence the probability distribution is conservatively based on the highest 200 half-hours of winter demand for 2007 and 2008.

Figure 14: Distribution of interruptible load (winter day epoch)



2.5 Transmission assumptions

2.5.1 The simulation model assesses the level of surplus capacity in the South Island which is available for transfer to the North Island via the HVDC link. For this analysis, Pole 2 and ½ pole 1 were assumed to be available if the deficit in the North Island warrants it. A sensitivity case was considered for the case where ½ pole 1 is not available.

2.5.2 A Customer Advisory Notice (CAN) was issued on May 8, 2008 by the System Operator that outlined the operating procedure for Pole 1. The CAN points out that there is provision for Pole 1 to operate in overload mode up to 284 MW, which at 668MW (700MW less losses) implies reserves cover of 384MW. As this is less than the 400MW supply-side reserve, there is the potential for Pole 2 to operate at 500MW should there be a sufficient South Island surplus.

2.5.3 When North Island reserves can be met without Pole 1, any contribution of a South Island surplus to North Island demand is only via transfers on Pole 2. The effective contribution is limited to 400MW (received), since any additional flows would need to be covered by additional reserves, so would not, in net terms, make any difference to the sum of demand and reserves.

2.5.4 There are several assumptions which apply for both configurations:

(a) If simulated HVDC flows are below maximum capacity, then a contribution of up to 25 MW to North Island supply is allowed and reflects the ability of Pole Two to temporarily increase flow to cover an unexpected outage.

(b) A forced outage rate of 0.25% is applied to either configuration. This is based on an assessment of historic outages and was discussed in the Annual Security Assessment (2007).

(c) Losses on Pole 2 flows are based on the formula $.0000995 \text{x} \text{flow}^2$. At a flow of 500MW on pole 2, losses are around 24MW. Losses for Pole 1 are based on the formula $.00025 \text{x} \text{flow}^2$. At a flow of 200MW on pole 1, losses are 10MW. With maximum flow of 700 across both poles, the received flow after losses is 665MW, which is comparable with the maximum of 668MW referred to in the CAN.

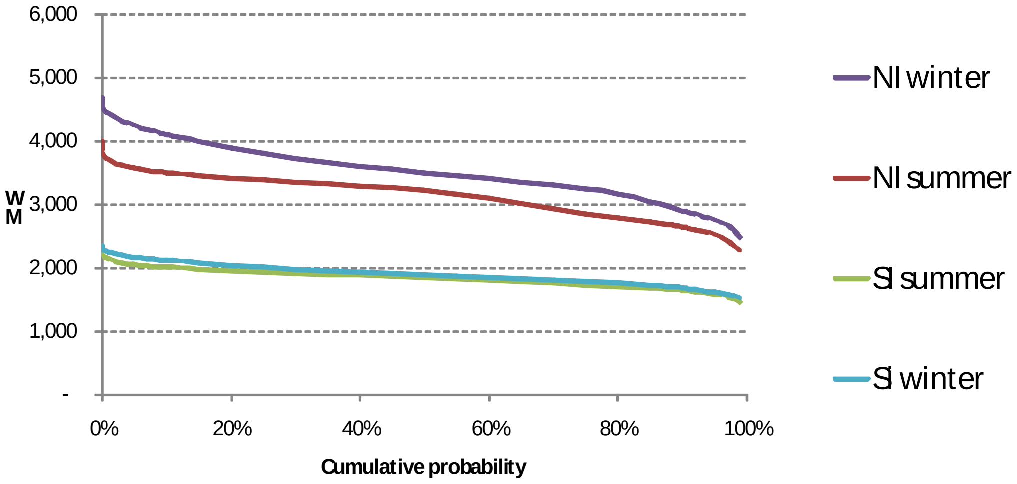
2.5.5 The limits on the operation of ½ Pole 1 have not been considered in the LDC convolution approach. However, they were examined as part of the chronological modelling (see paragraph 4.3.9 in Appendix 4).

2.6 Demand assumptions

2.6.1 Load duration curve forecasts were developed that were consistent with the Commission's energy and peak demand forecasts used for the Annual Security Assessment (October 2007).

2.6.2 Forecasts were provided for the period 2008-2012 for North/South Islands and for each epoch. Figure 15 illustrates the 2008 load duration curves. Distributions for 2011-12 were derived by scaling the 2010 distribution by the growth rate of annual energy. This was done in order to maintain the variability in the demand distributions similar to that expected over the relevant period for forecasts used when assessing capacity margins.

Figure 15: Expected load duration curves (2008)



2.6.3 Note that these expected LDCs are sometimes referred to as "load probability curves" because they do not represent one year of load, but rather the probability weighted average of many simulated LDCs. In order to align the variability in the demand forecasts with the scope of the assessment of the margin, demand for 2012 was based on the "shape" of the 2010 curve, but grown at the equivalent rate.

2.6.4 The Commission's forecasts are at the GXP level, and have been adjusted for estimates of intra-half hour variation and losses. The assumptions used here are consistent with those reported in the NWG's February 2008 report, as shown in Table 13.

Table 13: Adjustments to demand and ancillary services

Epoch	North Island	South Island
Losses	2.88%	4.88%
Intra-half hour variation	40 MW	12 MW
Frequency keeping	50 MW	50 MW
Reserves	400 MW	120 MW

2.6.5 The capacity margin calculations referred to in the report used a measure of winter demand based on the average of the highest 200 half-hours of winter daytime demands (including losses by excluding intra-half hour variation). These values are shown in Table 14. For reference, the expected highest half hour peak (including losses) from the demand distributions is also included.

Table 14: Demand inputs to capacity margin calculations

	2008	2010	2012
North Island expected peak (P50)	4,604	4,850	5,065
North Island average of highest 200 half-hours of winter daytime demand (H200)	4,369	4,576	4,746
South Island expected peak (P50)	2,317	2,413	2,507
South Island average of highest 200 half-hours of winter daytime demand (H200)	2,230	2,313	2,397

All figures include losses and exclude any intra-half hour adjustments

Appendix 3 Modelling results

3.1 Discussion of core analysis

3.1.1 This section describes the results from applying the LDC modelling approach to a base case set of input assumptions, along with the sensitivity of these results to changes to input assumptions that are particularly uncertain (e.g., costs of capacity shortfall). Included in the input assumptions are the conclusions of the chronological modelling discussed in Appendix 4.

3.1.2 The capacity adequacy standard is intended to be resilient for a minimum of 3 years out to 2012. Given the potential change in plant mix over that time, two plant mix scenarios and two demand scenarios were used as the "base case" set. LDCs for 2008 and 2012 were combined with two sets of supply mix assumptions:

(a) "Base" scenario: the current plant mix; and

(b) "Wind" scenario: the current plant mix with 400MW of wind added to the North Island (assumed correlated with at Tararua). The additional wind in 2008 would increase the capacity share of wind from approx 5% to 10% in the North Island.

3.1.3 For clarity, these scenarios are outlined in Table 15, and all include the operation of half Pole 1 at times of capacity shortfall.

Table 15: Base case scenarios

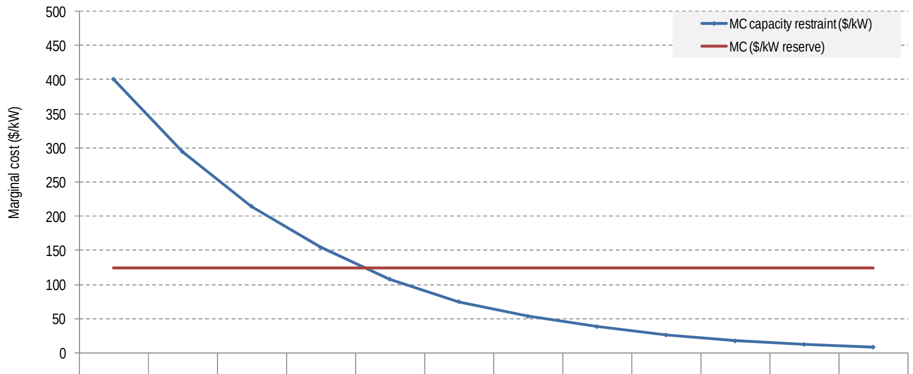
Scenario	Description
Base '08	2008 forecast demand 2008 capacity mix (wind is 5% of NI nominal capacity)
Wind '08	2008 forecast demand 2008 capacity mix with an extra 400MW added wind correlated with Tararua site (wind is 10% of NI nominal capacity)
Base '12	2012 forecast demand 2008 capacity mix (wind 5% NI nominal capacity, with demand growth met from base load capacity such as geothermal)
Wind '12	2012 forecast demand 2008 capacity mix with an extra 400MW added wind correlated with Tararua site (wind 10% NI nominal capacity, with demand growth met from base load capacity such as geothermal)

3.1.4 For all four cases, the same generic assumptions were made about summer/winter planned and forced outages.

3.1.5 The intention of the wind scenario was to increase the variability to the supply mix at peak times using a plausible assumption. This scenario is valuable for assessing the stability measures, and the methodology. It is important to recognise that future supply scenarios where new “firm” capacity (storage hydro, thermal and geothermal supply) is added are implicitly, and approximately, addressed by the modelling approach via the addition and subtraction of firm capacity to determine the optimal cost trade-off.

3.1.6 Figure 16 illustrates the marginal cost-trade off and adequacy measures for the Base 2008 case (based on expected annual costs).

Figure 16: Optimal trade-off curve for Base 2008 case



MC capacity restraint ($/kW)	$401	$295	$215	$154	$108	$75	$54	$38	$26	$17	$12	$8
MC ($/kW reserve)	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124	$124
USE (GWh)	3.4	2.4	1.8	1.3	0.9	0.5	0.4	0.3	0.2	0.1	0.1	0.0
USE (% annual demand)	0.008%	0.006%	0.004%	0.003%	0.002%	0.001%	0.001%	0.001%	0.000%	0.000%	0.000%	0.000%
LOLE (hours)	8.7	6.2	4.7	3.4	2.3	1.5	1.0	0.8	0.5	0.3	0.2	0.1
Nominal NI winter margin	1,019	1,069	1,119	1,169	1,219	1,269	1,319	1,369	1,419	1,469	1,519	1,569
Expected NI winter margin	597	647	697	747	797	847	897	947	997	1,047	1,097	1,147
Expected NI % margin	13.7%	14.8%	15.9%	17.1%	18.2%	19.4%	20.5%	21.7%	22.8%	24.0%	25.1%	26.2%

3.1.7 A number of possible adequacy measures were derived, as defined below.

(a) EUSE (GWh): expected annual GWh of involuntary restraint.

(b) EUSE (% annual demand): expected GWh of load shedding as a fraction of expected 2008 GXP energy demand (excluding losses).

(c) LOLE: expected number of hours of involuntary restraint per annum.

(d) NI nominal winter margin: total of installed NI MW capacity – highest winter half hour demand (P50 peak demand).

(e) Expected NI winter margin: This is the difference between expected North Island winter supply and demand, as summarised below. (The full definition is given in paragraph 3.1.27):

Term	Calculation
Expected North Island MW capacity	Calculated by derating plant based on type. • Controlled hydro and thermal capacity is counted at nominal capacity adjusted for planned and forced outages. • Uncontrolled plant is counted at the expected value of the distribution of output during winter days. • Wind is counted at 20% of nominal capacity • Expected value of IL offers • Effective voluntary demand response
+ effective South Island contribution	This reflects the effective contribution of South Island capacity after allowing for South the average of the highest 200 half-hours of winter daytime demands, an allowance for SI frequency and instantaneous reserves, and a diversity factor.
- H200 winter demand	This is the average of the highest 200 half-hours of winter daytime demand (including losses)

(f) Expected NI % Margin: 100* (Expected North Island winter capacity / average of the H200 winter demand -1).

3.1.8 The adequacy measures have been included on the x-axis to assist with understanding the implications at the optimum as charts later in the report only refer to the measures at the optimal point.

3.1.9 For the Base 2008 case, the optimal level of reserve capacity corresponds to a expected North Island winter margin of 776 MW (or 17.8% margin), expected involuntary load shedding of 0.91GWh (0.0022% of annual demand), and a loss of load expectation of 2.7 hours.

3.1.10 Observe from Figure 16 that changes to the assumptions about the costs of reserve MW can be derived by shifting the horizontal line to the desired $/kW cost and finding the intersection with the marginal cost of capacity restraint. For the expected NI winter margin:

- An $80/kW/yr increase in the cost of reserve capacity to $180/kW/yr would reduce the optimal margin by 53MW to 723MW.
- A $24/kW/yr reduction in the cost of reserve capacity to $100/kW would increase the optimal margin by 29MW to 805MW.

3.1.11 Figure 17 shows the optimal North Island winter margins (in MW) for all four base scenarios, with Figure 18 expressing them as a percentage of demand. Of particular interest here is the impact of additional wind capacity and changes to the demand forecast on the measures. In addition to the H200 demand, margins have been calculated from the expected peak demand (“P50 peak”), which is the highest expected half-hour demand. An alternative supply measure, based on nominal MW capacity, is also shown. Internationally the conventional margin is based on nominal peak capacity and P50 peak demand.

Figure 17: Base case optimal capacity margins (MW)

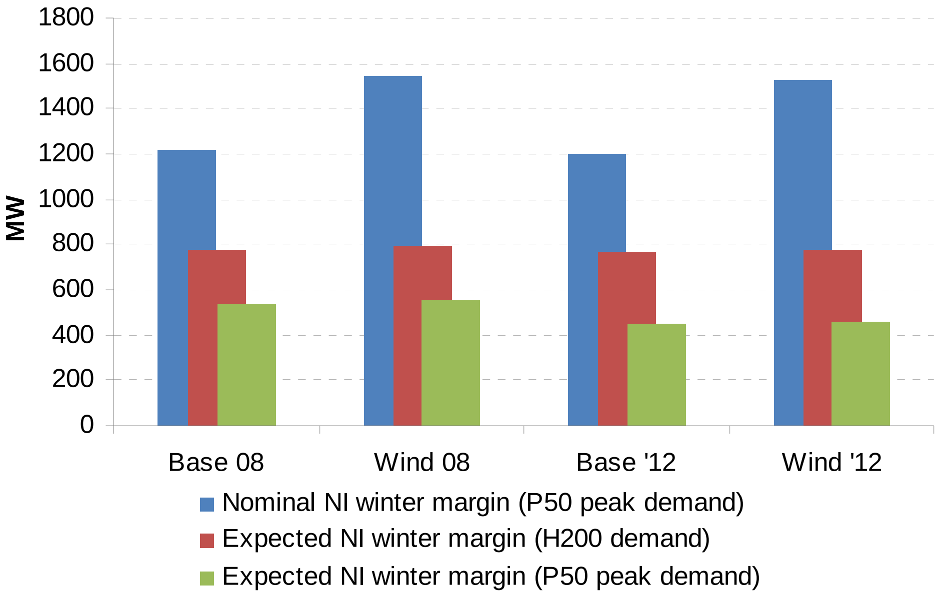
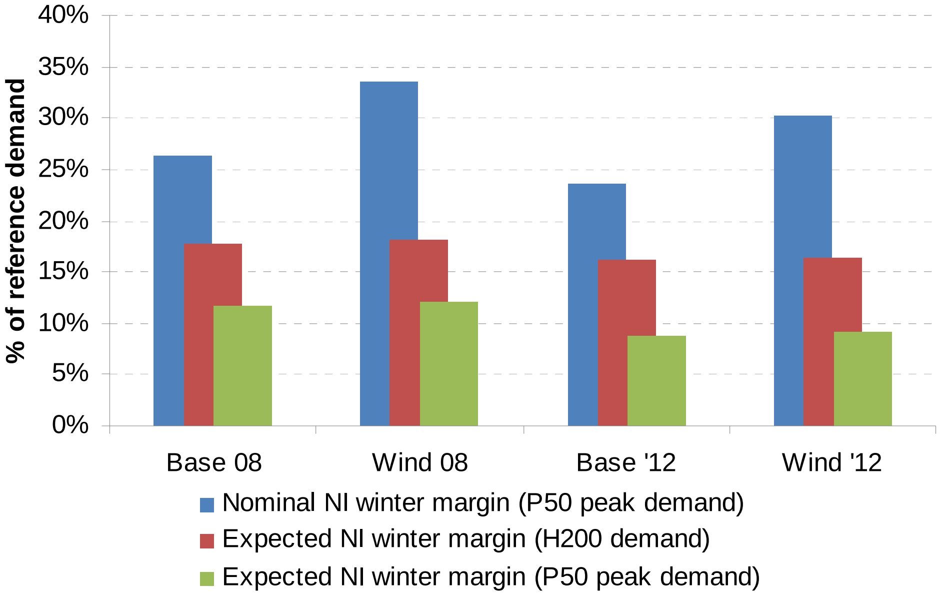


Figure 18: Base case optimal capacity margins (%)

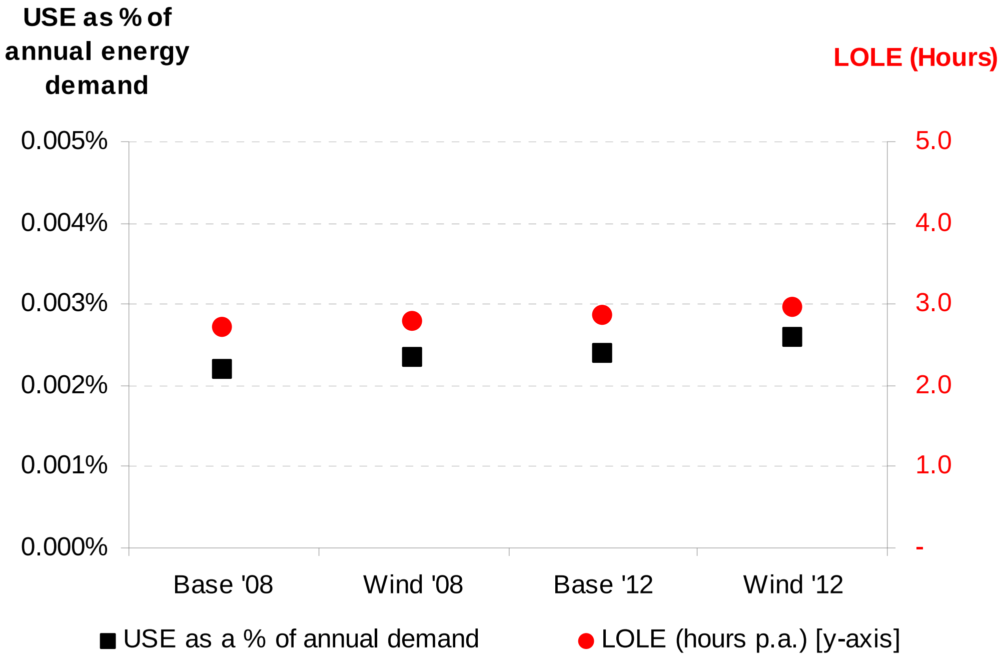


3.1.12 Observe that:

- The most stable measure across the supply mix and demand scenarios is the expected NI winter margin. This has an optimal value of around 770-790MW;
- Whether expressed in MW or as a percentage, margins calculated using nominal capacity or P50 peak demand are less stable across the scenarios;
- The optimal nominal NI winter margin increases if additional wind capacity is added. This is because it the effective capacity value of wind is much closer to the 20% factor used in the expected margin calculation;
- The expected NI margin over the “expected peak half-hour” varies from 450-550MW, broadly consistent with an N-1/N-G level (which corresponds to largest MW risk to the system from a generation or transmission contingency); and

3.1.13 For completeness, and comparison with international benchmarks, Figure 19 illustrates the optimal LOLP and EUSE (as a % of annual energy demand) for the base cases.

Figure 19: Base case optimal EUSE and LOLE

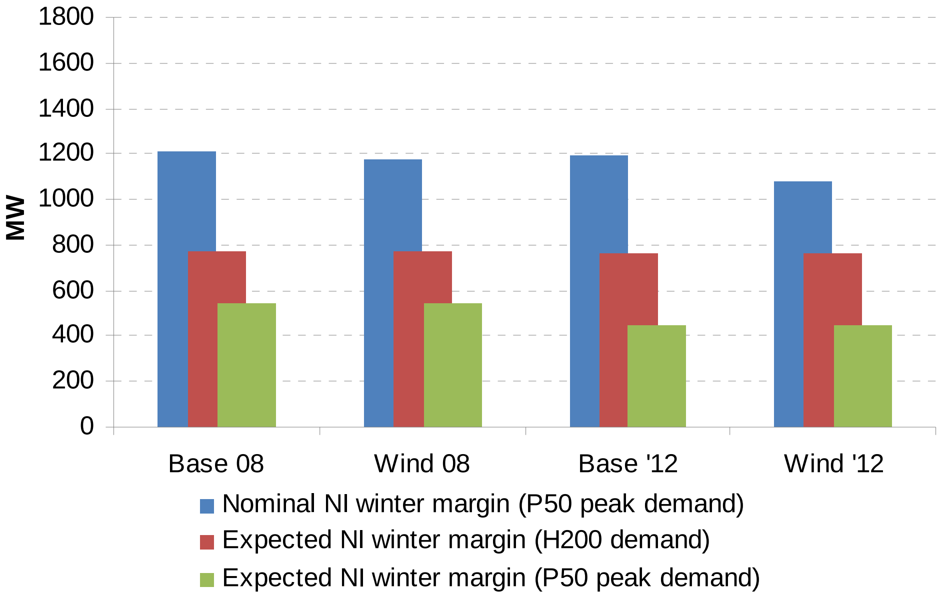


3.1.14 The quantum of involuntary restraint ranges from 0.0022% to 0.0026% of annual demand, broadly aligning with the 0.002% level applied for the Australian NEM. Involuntary restraint ranges from 2.7 – 3 hours, similar to the 2.4 hour standard applied in many of the North American markets, and the 3.5 hours in Australia.

3.1.15 Internationally, capacity adequacy margins are normally expressed in terms of nominal MW and P50 peak demands. Typical values are in the range 15% to 30% expressed on this basis[17]. The optimal NI margin expressed on a similar basis is between 24% and 34% depending on the percentage of wind capacity and the peak demand level (2008 or 2012). While the NZ margins appear to be at the high end of the international range, it is difficult to know the significance of this given the very different size and nature of the NZ system compared with these international comparators.

3.1.16 Figure 20 shows the impact of including or excluding half of Pole 1 of the HVDC.

Figure 20: Effect of excluding Half Pole 1 on optimal capacity margins



3.1.17 The expected NI winter margin (which includes the contribution from half of Pole 1) is relatively insensitive to the availability of half of Pole 1 of the HVDC. In effect, if it is contributing to North Island adequacy and unavailable then at the optimal capacity adequacy level it would need to be replaced with the equivalent MW from new (peaking) capacity; this dynamic is captured in the margin calculations.

3.1.18 In the process of deciding upon the form of the winter energy margins (17% NZ, 30% SI) it was apparent that a measure that was simple to communicate and calculate was desirable. Using the same logic, a margin expressed in MW which can be derived from input assumptions about supply and demand will be preferable to LOLP or EUSE measures, which the assessment using a an approach along the lines of that described in this paper. Using a MW margin means that the

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[17] See “Review of Methodology and Assumptions Used in NEMMCO 2003/4 Minimum Reserve Assessment”, KEMA, Jan 2005.

incremental effect of decisions can be assessed relatively quickly by the Commission and market participants alike.

3.1.19 Considering the MW options, the expected NI winter margin (calculated using the formula defined earlier) is a good candidate for a capacity adequacy standard due to its stability over the next few years and its relative insensitivity to the percentage of wind capacity.

3.1.20 The next section discuses the sensitivity of the adequacy measures to changes in other key assumptions.

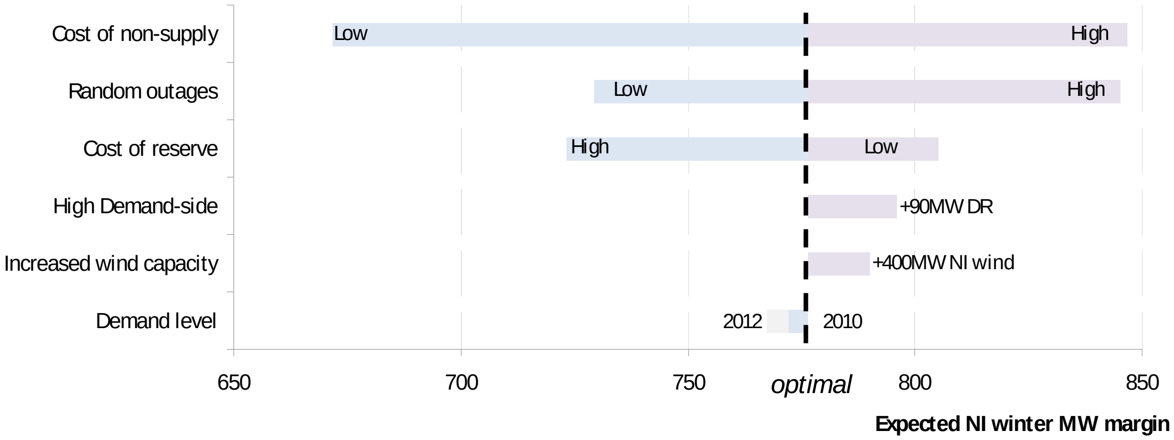
Sensitivities to key assumptions

3.1.21 Although the expected NI winter margin appears to be a relatively stable indicator of the optimal capacity margin, its level will depend on the assumptions about the economic drivers; the optimal level will clearly depend on the shape and level of the cost of capacity shortfalls assumed and the annualised cost of new peaking capacity.

3.1.22 Figure 21 below shows the sensitivity of the optimal expected margins (in MW and percentage terms) to variations in these drivers. The figure also shows the variation due to plant mix (high or low wind), the availability of Pole 1 and to the demand level (2008 to 2012). In Figure 21:

- The high and low costs of capacity shortfall curves were described earlier;
- The first block of involuntary load shedding varies from $11,000/MWh to $33,000/MWh (base assumption $22,000/MWh) and
- The annualised costs of new reserve capacity varies from $100/kW/yr to $180/kW/yr (base assumption is $124/kW/yr).

Figure 21: MW margin sensitivities (2008 base)



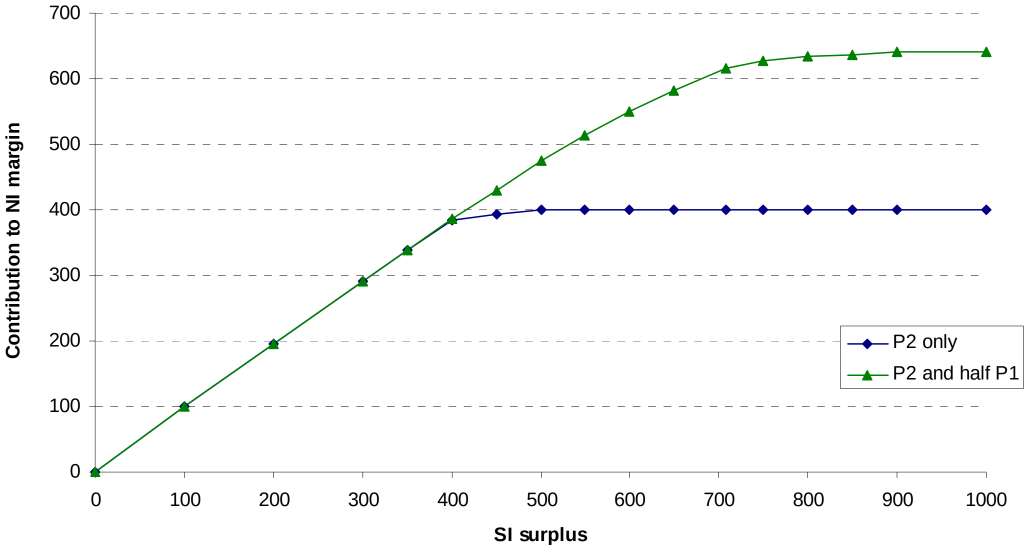
3.1.23 As can be seen the optimal margin changes by +70/-100 MW (2% of H200 demand) depending on the cost of capacity shortfall, whereas variations in the cost of new peaking capacity, demand level, plant mix and availability of half Pole 1 have less than +30/- 50MW effect.

3.1.24 While it is possible to refine the estimated cost of new peaking capacity, it is very difficult to refine the estimated range of shortage costs as they are inherently difficult to measure.

Calculating the effective contribution from the South Island

3.1.25 Figure 22 shows the effective South Island contribution across Pole 1 and Pole 2 for varying levels of South Island supply surplus. The SI surplus MW used in the calculation is the total expected South Island capacity minus the average of the highest 200 half-hours of winter daytime demand (including losses) minus 130MW[18].

Figure 22: Contribution of Expected South Island winter surplus to North Island MW winter margin



3.1.26 The curves have been derived empirically to represent the effective maximum contribution of the HVDC to the North Island for use in the (North Island) expected winter margin calculation.

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[18] The offset accounts for instantaneous and frequency keeping reserves within half-hour variation minus a diversity factor. This is found empirically by fitting a curve to the actual capacity value in a number of scenarios with different SI MW margins.

Definition and illustration of margin calculation

3.1.27 The Expected NI MW is determined by subtracting a measure of North Island Expected Demand from North Island Expected Capacity using following formula (all units in MW):

T + W + B + H + DRIL + SI - D

where

- T = Installed capacity of North Island thermal generation sources allowing for forced and scheduled outages
- W = 20% of North Island wind capacity
- B = Expected winter daytime (1 April – 31 October between 7am and 10pm) generation available from North Island geothermal plant, the aggregate of all North Island cogeneration plants, and the aggregate of all North Island uncontrolled hydro schemes.
- H=Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and derated to account for energy and other constraints which affect output during peak times
- DRIL = Expected demand response and interruptible load over the highest 200 half hours of winter demand (1 April – 31 October between 7am and 10pm)
- SI = The effective contribution of South Island capacity to North Island demand accounting for factors such as transmission limits and South Island demand (1 April – 31 October between 7am and 10pm).
- D = the average of the highest 200 half hours of forecast North Island winter daytime demand (1 April – 31 October between 7am and 10pm) at the points on the national transmission system at which generation enters the grid (with losses added).

3.1.28 For 2008, the margin is calculated in the table below, and includes New Plymouth but excludes Kawerau (90MW) and Ngawha II (15MW) geothermal plant which were commissioned during the winter of 2008.

Term	MW	Comment
Expected North Island capacity	4,733	See Table 6, which has a baseline of 4636 (including 10MW nominal demand response). To this is added 97MW for New Plymouth (100MW derated by 3%).
+ effective SI contribution	632	SI surplus is 3,137 – 2,230 – 130 = 788 MW. Reading off the HVDC curve illustrated in Figure 22, yields a contribution of 633MW.
subtotal	5,365	
- H200 North Island winter demand	4,369	See Table 14.
2008 NI winter margin	996	Exceeds 780MW standard by 216 MW

3.2 Comparison with National Winter Group (08) assessment

3.2.1 Although the capacity adequacy standard is not intended to be used for assessing operational security, there is some merit in aligning it with the analysis of the National Winter Group (NWG). The NWG updated its outlook for winter 2008 in February and again in June 2008[19]. In these reports, the NWG updated its assessments of available generation to meet North Island peak demand over June and July to account for changes to HVDC capability and the availability of a New Plymouth unit.

3.2.2 Adequate security in the NWG analysis was implied by a positive margin between the P10 generation capacity and the P95 peak demand (a prudent 1 in 20 year peak demand) plus normal ancillary service requirements (instantaneous reserves and frequency keeping reserves). The group initially assessed the margin without pole 1 as -107MW. When Pole 1 was subsequently made available, it assessed that there was a 83MW surplus in 2008 based on an instantaneous reserve requirement of 475MW to cover failure of pole 2 of the HVDC operating at 500MW. In the June report, the margin was revised to 240MW (surplus) due to the effect of the 100MW New Plymouth unit and clarification of reserve requirements when Pole 1 is in operation.

3.2.3 The comparison between the NWG's peak adequacy assessment for 2008 and the expected winter margin as calculated using the analysis described in this paper is shown in Table 16.

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[19] See National Winter Group 2008 Update Reports issued on 15 February 2008 and 6 June 2008.

Table 16: Comparison with NWG assessment of winter 2008

	Without Pole 1		**With 1/2 pole 1**	
	NWG	**EC**	**NWG ***	**EC**
Expected capacity		5,134		5,365
P10 Supply	5,270		5,442	
Highest 200 half hours demand		4,369		4,369
P50 peak NI demand	4,628	4,604	4,628	4,604
P95 peak NI demand	4,802		4,802	
1 Contingency	475		240	
Winter Margin		780		780
Surplus (N-1 Margin over P95 demand)	(7)		158	
Surplus (Economic margin)		(15)		216

3.2.4 The assessment of peak adequacy differs from the NWG's in many respects. The margin is assessed differently; it uses a different (more conservative) measure of expected peak supply capacity, a different benchmark of demand (the average of the highest 200 half-hours of winter daytime demand rather than a prudent peak) and a different required margin (780MW rather than a single contingency of around 400MW). In addition, the expected margin has been derived by an economic trade-off between the cost of capacity shortfalls and the cost of new peaking capacity taking into account the full range of variation in demand and plant breakdowns[20].

3.2.5 However as shown in the table above the conclusions are quite similar. Both approaches indicate that peak adequacy would be more or less achieved in 2008 without pole 1 of the HVDC, and that there is a degree of "surplus" capacity above the required standard with pole 1.

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[20] As noted, the methodology allows other adequacy measures to be estimated. For example, the implied LOLE for the current plant mix is 1 hour and expected involuntary capacity restraint is 0.3 GWh.

Appendix 4 Chronological modelling

4.1 Approach

4.1.1 The LDC convolution is approach is relatively straight-forward to implement and has been well tested. However it has some limitations in that it cannot directly account for chronological constraints, such as inflexibilities in thermal start up and river constraints affecting the available capacity of the hydro stations.

4.1.2 This appendix describes the chronological modelling was undertaken to determine the significance of these limitations and to derive an approach for incorporating them into the simplified LDC convolution analysis.

4.1.3 The key chronological issues that were likely to be most significant in the New Zealand system include:

(a) inflexibilities arising from river chain constraints;

(b) start up delays and ramping constraints for the major thermal units;

(c) major thermal unit commitment decisions made each day;

(d) correlation of load and wind generation;

(e) correlation of load between islands; and

(f) operational limitations on the use of pole 1 and pole 2 of the HVDC.

4.1.4 Rather than attempt a very complex chronological optimisation model we choose to base the modelling on historical data for the last 5 years. The demand and uncontrolled generation was scaled to reflect demand and capacity levels expected in 2010. This was supplemented by explicit modelling of the major thermal units and partly or fully controlled hydro systems approximately accounting for their chronological constraints.

4.1.5 The last 5 years data was broken up into 5 day periods and each period was modelled separately with 5 different forced outage scenarios.

(a) a 200-250MW outage (1 Huntly unit);

(b) a 350-500MW outage (1 CCGT unit or 2 Huntly units);

(c) a 600-700 MW outage (1 CCGT unit and 1 Huntly units);

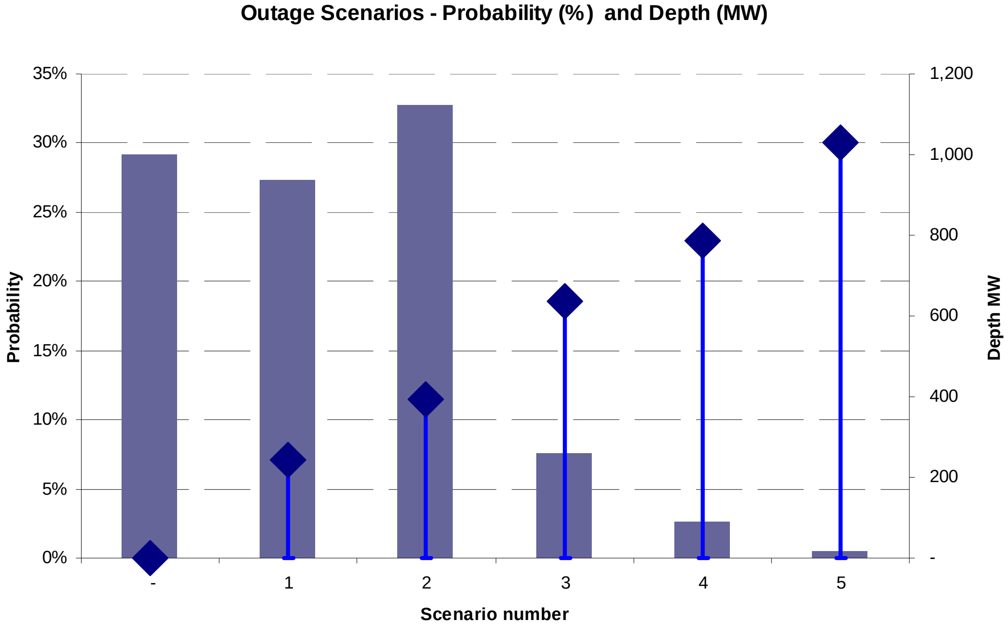
(d) a 700-800 MW outage (2 CCGT units or 1 Huntly and 1 CCGT units); and

(e) A greater than 1000MW outage (2 CCGT units and 2 Huntly units or worse).

4.1.6 In each 5 day period the availability of the small (less than 200MW) hydro and thermal units was randomly sampled[21]. Each day also used a range of different thermal unit commitments over a likely range reflecting forecast demand and historical hydro bidding patterns. In addition the starting time and duration of the major thermal outage scenario was randomly sampled.

4.1.7 In this way it was possible to model how the system responded a whole range of different shocks with different timings and depths under different system conditions and to derive the nature, extent and cost of any demand reductions required.

4.1.8 The probability weighting for each outage scenario was derived[22] in order to calculate the expected quantity and cost of shortages to be comparable with the LDC convolution approach. The probability of each shortage scenario is given in the chart below. This is based on a forced outage rate of 3% for the Huntly and CCGT units and expected outage duration of 24 hrs (around 10 outages per year). Note that the probability refers to the risk of an outage (of any length) of the relevant depth occurring within a 5 day period.



4.1.9 Note that with these parameters the probability of a single Huntly outage of 250MW occurring within a 5 day period is approx 28%, and a CCGT or 2 Huntly units is

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[21] These probabilities were found by convolving Huntly and CCGT outages assuming forced outage and return rates and grouping outages into the 4 categories of depth, and deriving an equivalent outage duration equal to the total outage over the 5 day period divided by the depth category. The assumed failure rate is given by the forced outage rate divided by the mean outage duration and the return rate is given as 1 – 1/OutageDuration.

around 33%. The probability of combined outages greater than 400MW is significantly lower at around 6%.

4.2 Assumptions

4.2.1 Generation plant was categorised into 5 groups:

(a) **Large Thermal** - modelled with explicit outage scenarios, minimum running levels, delay and ramping rates from hot, warm and cold states;

(b) **Small Thermal** - modelled with randomly sampled daily availability but otherwise sufficiently flexible to deliver full available capacity during a contingency;

(c) **Uncontrolled** - modelled as generating at historical levels;

(d) **Semi controlled hydro** – modelled at historical levels normally, but with the added capability running at full randomly sampled available MW for a limited time during a contingency; and

(e) **Controlled hydro** – modelled as sufficiently flexible to provide full randomly sampled available MW during a contingency.

4.2.2 The categorisation of plant and their assumed parameters are summarised in the following tables, where possible these have been aligned with the assumptions used in the LDC approach.

Large Thermal

Station	Island	Capacity MW	Units	Forced Outage Rate	Mean Outage duration	Planned Outage
Huntly	NI	972	4	3%	24hrs	1 unit out from Nov to Mar, river heating constraints during Jan and Feb
CCGT	NI	1,160	3	3%	24hrs	60 CCGT unit days planned outage over summer.

Unit Commitment	Cold	Warm	Hot	Notes
Hours from shut down	> 24	< 24	<3	
Huntly delay hrs	5.0	2.0	1.0	
CCGT delay hrs	3.0	1.5	1.0	
Hly Hrs to full load	20	5	2	
CCGT Hrs to full load	16	5	4	

Small thermal

Station	Island	Capacity MW	Units	Forced Outage Rate	Planned Outage	Notes
Southdown	NI	170	4	3%	Over summer	
Whirinaki	NI	155	4	3%	November	
HLY 45	NI	45	1	3%	Jan	

Uncontrolled

Station	Island	Capacity MW	Avg MW	Capacity Factor	Notes
Cogeneration	NI	177	108	61%	
Geothermal	NI	416	372	89%	
NI Wind	NI	252	50	20%	Includes West Wind
Rangipo	NI	120	66	55%	
NI Local Hydro	NI	68	35	51%	Mangahao, Wheao
SI Local Hydro	SI	44	14	33%	Argle, Opua, Teviot, Kumara
SI Wind	SI	58	12	20%	
NI Interuptible Load	NI		160		25% standard deviation

Controlled Hydro

Station	Island	Capacity MW	Forced Outage Rate	Notes
Waikaremoana	NI	137	2%	
Waitaki	SI	1,633	2%	180MW outage over summer
Clutha	SI	740	2%	
Manapouri	SI	721	2%	
Cobb, Coleridge	SI	72	2%	

Semi Controlled Hydro

Station	Island	Capacity MW	Forced Outage Rate	Peaking storage hrs	Notes
Waikato	NI	1,050	2%	5	for last 200MW
Patea	NI	32	2%	25	
Tokaanu	NI	240	2%	13	
Matahina	NI	77	2%	5	

HVDC

Station	Island	Capacity MW	Min Run hrs	Max /yr	Notes
Pole 2	SNT	400		unlimited	400MW available from pole 2 without increasing IR requirements in NI
Pole 1	SNT	266	4	240hrs or 20 starts	266MW additional from pole 1 and 2 without extra IR in NI

4.2.3 The MW available for HVDC transfer to the North Island during contingencies was determined from the spare South Island available capacity after meeting SI load and reserve requirements (instantaneous and frequency keeping). Pole 2 and half of pole 1 were assumed to be available during contingences[23].

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[23] Note that in the LDC convolution approach it is assumed that the HVDC had a random outage rate of 0.25%. This was not factored into the chronological modelling.

4.2.4 Note that New Plymouth is not included in the modelling and that the correlation between uncontrolled generation stations (geothermal, cogeneration and uncontrolled hydro) is preserved through the use of historical generation.

4.3 The impact of chronological constraints

4.3.1 As with the LDC convolution model, the chronological model can be run with a range of different levels of reserve capacity to determine the optimal capacity margin (trading off the cost of shortages against the cost of reserve capacity).

4.3.2 The impact of each chronological constraint was determined by adding each chronological constraint one by one and by determining the additional reserve capacity required to restore the optimal capacity margin.

Semi Controlled Hydro

Waikato Energy Constraint	More Flexible	Base Case	Less Flexible
Total MW	1,050	1,050	1,050
Unconstrained MW	870	850	750
Semi Controlled MW	180	200	300
Semi Controlled MWh	1,100	1,000	800
Max hrs at full capacity	6.1	5.0	2.7
Additional reserve MW required	47	55	117
Capacity Derating	4%	5%	11%

4.3.3 Treating the Waikato as semi rather than fully controlled requires an additional 47 to 117MW of reserve capacity depending degree of flexibility assumed. A capacity derating of 4-11% is required to account for chronological constraints.

Scheme	More Flexible	Less Flexible	Fully Uncontrolled
Matahina			
Semi Controlled MW	77	77	77
Semi Controlled MWh	400	200	-
Max hrs at full capacity	5.2	2.6	-
Additional reserve MW required	12	22	34
Capacity Derating	16%	29%	44%
Patea			
Semi Controlled MW	32	32	32
Semi Controlled MWh	800	200	-
Max hrs at full capacity	25.0	6.3	-
Additional reserve MW required	2	7	14
Capacity Derating	5%	21%	43%
Tokaanu			
Semi Controlled MW	240	240	240
Semi Controlled MWh	3,000	1,000	-
Max hrs at full capacity	12.5	4.2	-
Additional reserve MW required	20	64	100
Capacity Derating	8%	27%	42%

4.3.4 Treating Matahina as semi rather than fully controlled requires an additional 12 to 22MW of reserve capacity (16-29% derating), whereas treating Patea as semi controlled only requires an extra 2-7MW (5-21% derating). This is because Patea has relatively more short term storage and can operate at maximum for a longer time during contingencies. Lack of full control at Tokaanu is worth around 20 to 64MW, implying a capacity derating of 8-27%. Note that treating these schemes as totally uncontrolled would require a substantially greater 42-44% capacity derating.

Major Thermal with ramping and start up constraints

5.1.7 The impact of ramping and starting time constraints on the major thermal plant appears to have a relatively small impact of less than 40MW (i.e. less than 2% derating). Note that this results from the major thermal units typically being committed during peak winter periods when the risk of demand restraint is greatest. The ramping and unit commitment issues are more significant in summer and may become much more significant if there is significantly more wind on the system.

Thermal Ramping Limit	More Flexible		Less Flexible	
	Cold	Warm	Cold	Warm
CCGT & HLY Capacity MW	2,132		2,132	
CCGT Start time hrs	3.0	1.5	9.0	4.5
HLY Start time hrs	5.0	2.0	15.0	6.0
CCGT hrs to full load	16	5	32	10
HLY hrs to full load	20	5	30	10
Additional reserve MW required	2		40	
Capacity Derating	0.1%		2%	

Partly Correlated Wind

4.3.5 The capacity value of additional wind can be assessed in a similar way. The table below shows the reduction in optimal reserve capacity resulting from an extra 200 and 400MW wind in the North Island.

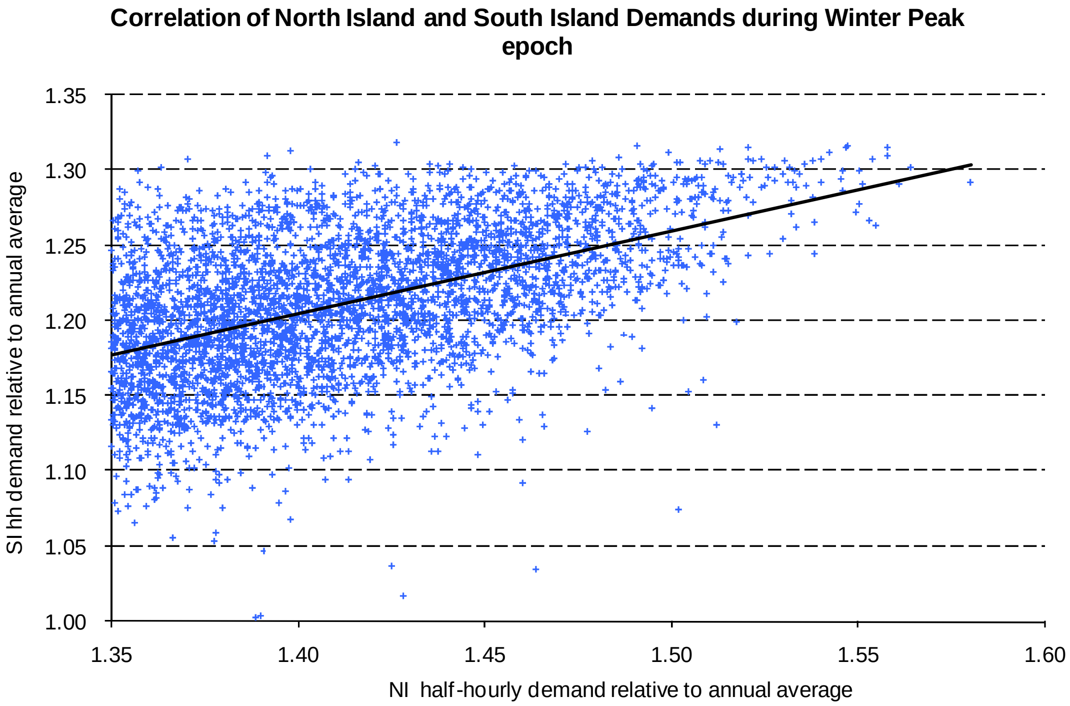
Additional Wind Capacity	NI Wind + 200MW	NI Wind + 400
NI Wind	200	400
Decrease in optimal reserve MW	43	74
Capacity Derating	78%	82%

4.3.6 This indicates that additional wind capacity needs to be derated by 78-82% to make it equivalent to perfectly flexible firm reserve capacity. This implies a firm capacity value of approximately 22-18%. Note that the level of derating increases as the total capacity of wind on the system increases.

Partly Correlated North, South Island Demand

4.3.7 The earlier analysis conservatively assumed that South Island peak demands were coincident with peak North Island demands. However in reality the correlation is less than 1 as shown in Figure 23.

Figure 23: Correlation of North and South Island demand



4.3.8 The chronological modelling approach naturally factors in this partial correlation through the use of 5 years of historical demand data. Accounting for this partial correlation increases the effective South Island surplus capacity available to the North Island by around 70 to 80MW. Note that it is also possible to include this partial correlation between North and South Island demands directly in the LDC convolution approach.

HVDC Scheduling

4.3.9 The chronological model can be used to assess the significance of the chronological constraints on the use of Pole 1. The analysis indicates that an expected 170-200hrs of Pole 1 operation (accounting for the minimum 4 hour run time) would be required at the optimal reserve generation level until 2012. This implies around 20 to 30 starts. The number of operating hours is within the 240hr limit, but the expected number of starts is slightly higher than the 20 allowed. However this assumes very limited market based demand response (on 10MW in the North Island), in reality significantly more demand response is expected and this would significantly reduce the need to schedule Pole 1.

4.4 Conclusions

4.4.1 The chronological modelling confirms that the inaccuracies associated with the LDC convolution are not great and can be handled by appropriate categorisation of generation plant with appropriate derating factors and by better accounting of correlations between uncontrolled plant and between North and South Island demands.

4.4.2 The recommended changes for the LDC approach include the following:

(a) Account for the partial correlation between North and South Island demands in the LDC convolution approach;

(b) Aggregate the uncontrolled generation in each island, by category, to preserve historical correlations;

(c) Treat Waikato (including Karapiro which was previously treated as uncontrolled) as controlled hydro, but derated by 60MW (6%) to account the impact of chronological constraints;

(d) Treat Matahina, Patea and Tokaanu as controlled but derated by 13MW, 5MW and 20MW to account for their limited short term storage;

(e) Treat Cobb and Coleridge and Roxburgh as controlled rather than uncontrolled as they have sufficient short term storage to enable full output during contingencies; and

(f) Treat major thermals as fully controlled since the impact of unit commitment, delays and ramping did not appear to be a significant issue during peak demand periods over the next few years.

Appendix 5 Technical Discussion

5.1.1 For the benefit of technical modellers, this appendix clarifies and justifies some technical aspects of the methodology in response to issues raised in submissions.

Concept of the standard

5.1.2 Capacity adequacy refers to the ability to meet demand for generation in each island during periods of peak demands and/or supply outages. It accounts for transmission constraints between the islands but does not account for localised transmission constraints within each region.

5.1.3 The Commission has chosen to develop a Capacity Adequacy Standard (CAS) in the form of a MW capacity margin out to 2012 as it is simple to apply while also capturing the contributions of various supply sources to meeting (short-term) demand requirements.

5.1.4 The optimal capacity margin is assessed by trading off the economic cost of peaking capacity against the economic costs of capacity shortfalls.

5.1.5 The margin should be re-assessed to account for significant changes in the plant mix and for any significant changes in the assessed cost of non-supply and/or the cost of peaking capacity.

5.1.6 Although the primary measure of the Capacity Adequacy Standard is the MW capacity margin, supplementary measures including the Loss of Load Probability (LOLP) and the expected unserved energy (EUSE) are also derived.

Application of the Standard

5.1.7 The standard will be used as an “orange” warning indicator of capacity adequacy in the North Island[24] within the lead time of new peaking capacity (1-2 years).

Methodology to Determine the Standard

5.1.8 The Commission has developed the optimal capacity margin using a simplified probability convolution approach.

5.1.9 The key technical aspects of the methodology are summarised below:

(a) The capacity standard is calculated by determining the additional supplementary peaking capacity (positive or negative) needed to achieve an

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[24] A Capacity Adequacy margin for the South Island may be developed in the future.

optimal peaking capacity level where the expected marginal cost of capacity shortfalls equals the marginal cost of peaking capacity[25];

(b) The probability distribution of capacity shortfalls is derived as the difference between the probability distributions of the demand for, and the supply of, generation capacity;

(c) Four separate time zones (Winter/Summer/Peak/Off-peak) are used to account for the timing of scheduled and deferrable outages and the seasonal variations in demand and uncontrolled supply;

(d) Demand for generation capacity is treated as a probability distribution of half hourly load including normal random variations within a year and out to 1-2 years ahead;

  (i) North and South Island half hour demands are treated as separate but partly correlated distributions. Demand includes transmission losses and an allowance for within half hour variation. There is an additional requirement for instantaneous reserves (Fast or Sustained) and frequency keeping reserves. This is set at a constant level of 400MW for IR equal to the largest CCGT unit[26] plus 50MW for frequency keeping; and

(e) Generation supply is categorised as controlled or uncontrolled;

  (i) Uncontrolled supply (wind, geothermal, cogeneration and run of river hydro) is represented by historical distributions aggregated as appropriate to preserve correlations between different plant[27];

  (ii) Supply of instantaneous reserve from interruptible load is treated as uncontrolled with a probability distribution with a mean and variance reflecting the historical offers available at times of peak demand[28];

  (iii) Controlled supply (flexible thermal and flexible hydro with significant storage) is represented as being fully available to meet peak demand, but subject to random unit outages; and

  (iv) Flexible hydro or thermal plant subject to chronological constraints are treated as controlled supply, but have their peak capacity derated to reflect the impact of chronological constraints[29].

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[25] Note that this in contrast to the traditional screening curve analysis which indicates the optimal investment in all types of plant, not just peaking capacity.

[26] It is conservatively assumed that at least one CCGT will be running at full capacity at times of capacity shortfall.

[27] Ideally the distribution of new wind generation should be synthetically derived from the historical correlation between wind at the existing farms and wind at the new wind farms. For the current analysis it is assumed that West Wind is 100% correlated to wind at Tararua. This is conservative and could be refined in the future.

[28] Note that there is a negative correlation between IL and demand, and hence the probability distribution is conservatively based on the highest 200 half-hours of winter demand for 2007 and 2008.

5.1.10 Supply probability distributions are convolved directly[30] as it is assumed that all capacity that is available will be scheduled to avoid capacity shortfalls. Random outage rates used in the analysis within each time zone are conditional (i.e. the probability of failures given that the plant is running) but independent of load. It is assumed that random outages are independent between units[31].

5.1.11 Supply available from the South Island to the North Island is accounted for through a sampling convolution approach[32]. This allows for the partial correlation of North and South Island demands to be accounted for as well as outages of the HVDC link itself:

(a) Supply available from the South Island via the HVDC is limited so as not to increase the assumed demand for Instantaneous Reserves set by the largest CCGT unit: and

(b) Based on historic performance, the forced outage rate for the total HVDC is assumed to be 0.25%. Although the outage rate is very low, the impact is relatively large since an HVDC outage represents a net loss of around 660MW of peak supply capacity in the North Island.

5.1.12 The expected cost of capacity shortfalls is derived from the probability distribution of capacity shortfalls[33] and the cost which is assumed to vary with the depth of shortfall[34]:

(a) The cost of capacity shortfall reflects the net cost of market, voluntary or imposed demand reductions above the short run running costs of an open cycle peaking plant[35] (approx $200-400/MWh);

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[29] The derating reflects the “capacity equivalent” impact of the chronological constraints. The Capacity Equivalent impact is the extra firm peaking capacity required to restore the optimal capacity margin. This is derived from a supplementary chronological model, or by judgement.

[30] The convolution is performed directly on the probability distributions using a Fast Fourier Transform convolution rather than iteratively as would normally be the case in a production costing methodology (such as in the traditional Booth-Baleriaux approach). This is possible since we only need to derive the probability distribution of capacity shortfalls and do not require estimates for the probability distributions for the generation from each plant type.

[31] There can be correlations between unit outages within a plant or due to failure of a common fuel. These are not considered to significant in the New Zealand context.

[32] Using 100,000 random draws.

[33] The capacity shortfall distributions from each time –zone or epoch are combined to give a total annual capacity shortfall distribution.

[34] The simplified convolution approach provides a probability distribution for the depth of capacity shortfalls but not the duration.

[35] Defining capacity shortfall costs in this way enables the annual fixed costs of a peaking plant (capital recovery and fixed operations and maintenance costs) to be compared directly with the expected marginal capacity shortfall costs. There is no need to explicitly account for the expected short run marginal cost (SRMC) of operating peaking plant. Note that demand for electricity is that which would be expected at spot prices less than the SRMC of peaking plant (around $300/MWh).

(b) It is assumed that the system operator will back off the requirement for Instantaneous Reserve and operate the system in an “emergency secure” state before instructing load shedding;

(c) While the system is in an emergency secure state the risk of AUFLS blocks being tripped is higher than normal. The expected cost of these accounts for the probability of a trip, and the cost, depth and duration of a trip of each AUFLS block relative to the level of capacity shortfall. The expected cost is assumed to be $1,000 to $6,000/MWh, significantly less than the cost of instructed load shedding;

(d) It is conservatively assumed that the cost of instructed load shedding increases from around $10,000 to $100,000/MWh depending on the depth of load shedding required and the extent to which load shedding is shared equally; and

(e) There is scope for voluntary or commercial market-driven demand side response but this would require strong market incentives (i.e. the risk of very high spot prices resulting from capacity shortfalls) or other commercial arrangements (e.g. via contracts for demand response from the system operator). Current market rules do not provide particularly strong market incentives for voluntary response and the system operator does not generally contract for demand response (although the Grid owner has trialled such contracts as an alternative to transmission investment).

Definition of the Margin calculation for Monitoring

5.1.13 The methodology above can be used to determine the optimal additional capacity required for a given plant mix and for a given future demand level.

5.1.14 The analysis was repeated for the range of different demands and plant mixes expected over the few years. A range of different versions of the capacity margin was calculated and a definition that gave a stable MW measure over the range of years and capacity mixes was chosen.

5.1.15 It should be recognised that the choice of the margin definition and the optimal MW level is relatively arbitrary. There is a range of different definitions and corresponding levels that are relatively stable and could be used for monitoring.

5.1.16 Regardless of which definition is used, it is important that optimal level (margin standard) is consistent with the definition. The definition of the margin is just a proxy for the underlying optimal capacity margin which reflects the trade off between the cost of additional peaking capacity and the cost of capacity shortfalls.

5.1.17 The Commission has chosen to use the following definition for the capacity margin:

NI Winter MW Capacity margin = Expected NI capacity – H200 NI Demand

The H200 NI Demand is the average of the highest 200 half-hours of North Island winter daytime demand including transmission losses, but excluding within half-hour variation and the demand for instantaneous and frequency keeping reserves[36].

5.1.18 The expected NI capacity is calculated by derating plant based on type:

(a) Controlled hydro and thermal capacity is counted at nominal capacity adjusted for scheduled outages. The capacity is further derated for forced outages and for the capacity equivalent impact of chronological constraints;

(b) Uncontrolled plant (cogeneration, geothermal and uncontrolled hydro) is counted at the expected (average) value of the distribution of output during winter daytime. Output for cogeneration and hydro plant have each been aggregated;

(c) Interruptible load offered for IR is counted as the expected (average) value of offers expected to be available during the highest 200 half- hours of winter peak demand;

(d) Wind is counted at 20% of nominal capacity. This 20% factor represents the capacity value of wind[37]. The capacity value is determined empirically and will depend on the degree of correlation between new wind supply and the existing wind and the total proportion of wind in the system. The factor should be updated when significant additional wind capacity is added;

(e) The HVDC transfer capability is derived from an empirical lookup function of SI surplus supply;

    (i) South Island surplus supply is defined as expected SI winter supply minus the average of the highest 200 half-hours of winter daytime SI demand (including losses) minus an empirical 130MW;

    (ii) This curve is derived by running the full convolution model with different levels of South Island demand and SI capacity and calculating the impact on the optimal capacity required in the North Island. This curve accounts for the HVDC outages, the historical correlation between North Island and South Island demand including the 182MW requirement for

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[36] Note that the level of demand chosen for use in the margin calculation is just a proxy, the underlying calculation of the optimal margin includes the full distribution of half hour demand variation, within half hour variations and frequency keeping and instantaneous reserves.

[37] This is defined as the level of firm oil fired peaking capacity replaced by wind capacity while maintaining the optimal trade off between capacity and the cost of capacity shortfalls. The 20% is an approximate value derived from the chronological modelling based on historical wind generation at Tararua. Ideally this should be refined to account for the actual correlations between new wind generation and existing wind generation at Tararua.

instantaneous and frequency keeping reserves and within half hour variations (assumed to be 120MW, 50MW and 12MW respectively);

(iii) Note that the empirical 130MW offset is less than the 182MW of reserves due to the diversity between NI and SI demands; and

(iv) This empirical curve will need to be updated if the availability and performance of half of pole 1 is changed or if the HVDC is upgraded; and

(f) The MW contribution from voluntary or contracted demand response depends on the cost. If the cost is of the same order as the running cost of oil fired peaker then it would be counted at its full MW. If the cost of demand response was $4000/MWh each additional MW of demand response would only reduce the optimal peak capacity requirement by 0.5MW therefore it would be counted at 50% of its nominal level in the margin calculation. A notional 10MW is assumed for demand response.

Variation of the Optimal Margin

5.1.19 The 780MW NI Winter MW Capacity margin has been derived on the basis of a middle point estimate of the cost of capacity shortfall curve and an assessed incremental oil fired peaker fixed capacity cost of $124/kW/yr[38].

5.1.20 It would be possible adjust this margin for changes in the cost of peaking capacity in the future if desired. The optimal margin decreases by approximately 10MW for each $10/kW/yr increase in the fixed capacity cost.

5.1.21 It would also be possible to adjust the margin for changes in the assessed cost of capacity shortfall curve. The optimal margin would increase by approximately 15MW for each 10% increase in the capacity shortfall cost.

5.1.22 As described earlier, the capacity shortfall cost is measured relative to the SRMC of an oil fired peaker. This can vary from $200 to $400/MWh. A $100/MWh increase in the SRMC of an oil fired peaker would decrease the optimal margin by around 2MW. This is not worth adjusting for as it is within the margin of error.

5.1.23 The optimal margin can vary as a function of the assumed forced outage rate for the major thermal units (Huntly and the CCGTs). For example an increase in the assumed forced outage rate from 3% to 5% would increase the margin by approximately 65MW.

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[38] Note that the fixed capacity cost is assumed to be independent of the utilization factor of the peaking plant.