



# **Electricity Security of Supply Policy Review**

**Final Report**

**May 2007**



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## Glossary

<b>Absolute Security of Supply</b>	Certainty that Energy and Capacity available will exceed demand at all times
<b>Absolute Security Standard</b>	A security standard that aims to provide Absolute Security of Supply
<b>ACAP</b>	Available Capacity Mechanism. This is a mechanism in use in the PJM West jurisdiction of the United States. Obligations are imposed on each purchaser to procure capacity 'tickets' in proportion to their contribution to peak load, and generators must make tickets available for sale. The objective is to ensure capacity adequacy by imposing a total requirement to hold capacity tickets that is equal to the level of capacity estimated to be necessary to achieve the desired level of Security of Supply
<b>Act</b>	The Electricity Act 1992
<b>Adequacy</b>	With respect to a Resource, the level of that Resource which ensures that demand for that Resource can be met at the required level of Security of Supply
<b>Adequacy Tickets</b>	A possible intervention in the market to ensure security of supply. Adequacy Tickets could be defined either in terms of Capacity or Energy Adequacy. Adequacy tickets could be sold by those who have the Resource in question to those required to hold such tickets at a level estimated to be sufficient to cover their demand for that Resource
<b>Arrangements</b>	The reserve energy Regime and Policy
<b>Baseload</b>	A generating plant with high fixed costs and low variable costs designed to be run continuously for most of the year.
<b>Ben Price</b>	The wholesale price of power at the Benmore Node
<b>Benmore</b>	A hydro-generation station of that name on the Waitaki River in the South Island
<b>Cap Contracts</b>	An Energy Call Option
<b>Capacity</b>	The capacity of generating equipment to produce energy per unit time, measured in megawatts
<b>Capacity Adequacy</b>	Having enough capacity to meet peak demand at the desired level of peak security of supply
<b>Centralised Resource Adequacy Mechanism (CRAM)</b>	A centralised procurement version of ICAP which has been specifically developed to replace ICAP-type mechanisms in some eastern US markets. Takes a longer term view than ICAP/ACAP, with capacity requirements and loads forecast and tickets procured some years in advance
<b>Centrally Procured Dry Year Insurance Scheme with Opt-Out</b>	A possible intervention in the market to ensure security of supply, proposed by NERA. Similar to 'Compulsory Dry Year Insurance' except levy is avoidable by self 'insurance', and the Commission will procure contracts to meet net demand
<b>Commission</b>	The Electricity Commission
<b>Compulsory Dry Year Insurance</b>	A possible intervention in the market to ensure security of supply, proposed by WEMDG prior to the development of the wholesale electricity market
<b>Contingency-Specific Failure</b>	A type of market failure, whereby the market might not provide optimally for some specific contingencies, such as dry years, but generally delivers sufficient resources to meet demand in all other circumstances
<b>CRA</b>	Charles River Associates

<b>Current Reserve Energy Policy</b>	The Reserve Energy Policy currently adopted by the Commission
<b>Demand Restraints</b>	Any mechanism intended to reduce electricity consumption below normal levels in order to keep electricity consumption below the level of available supply. Includes warnings of shortages, conservation campaigns and direct controls like pre-announced rolling power cuts
<b>Dry Year</b>	A period in which hydro inflows are significantly below normal
<b>Dry Year Capacity Rating (DYCR)</b>	A rating of a generator indicating the amount of energy it could reliably provide in a Dry Year
<b>Dry Year Energy Call Options</b>	A contract which gives the holder of the contract the right (but not the obligation) to require the seller of the contract to provide it with a specified amount of energy, over a specified period, at a specified price, in a Dry Year. For the purposes of this report the definition requires the contract to be physically backed, and to have a strike price no higher than the highest probable market price in a shortage situation
<b>Dry Year Price Insurance</b>	A possible intervention in the market to ensure security of supply, proposed by Contact and NERA. Obligations are imposed on purchasers to procure cap contracts. Any deficiency is procured by the Commission and the costs and contracts allocated to the relevant un-hedged purchasers
<b>Dry Year Reliability Guarantee Contracts</b>	A possible intervention in the market to ensure security of supply, proposed by M-co. High strike price cap contracts are purchased by the Commission on behalf of all consumers
<b>Dry Year Security Hedges</b>	A possible intervention in the market to ensure security of supply, proposed by Contact and NERA. Obligations are imposed on purchasers to procure cap contracts or other hedges. The Commission does not take on the role of procuring any residual contracts, but rather imposes high penalties for failure to comply
<b>Dynamic Distortion</b>	An intervention that incentivises a less efficient generation portfolio and dispatch pattern than would have been possible without intervention, and hence increases the overall costs of electricity
<b>e3p</b>	The new 'combined-cycle gas turbine' plant to be commissioned by Genesis Energy in 2007
<b>Economic Security Standard</b>	A Security Standard set to maximise economic welfare by achieving the optimal balance between the costs of non-supply and the costs of increased security
<b>Energy</b>	Electricity energy, measured in the kWh. The product of fuel converted into electrical energy through the operation of generation Capacity
<b>Energy Adequacy Hedges</b>	A generic term for encompassing Dry Year Energy Call Options, Forward Contracts for Energy in a Dry Year, and ownership and control over plant capable of generating in a Dry Year. Any of these instruments would allow a Load Serving Entity to meet its demand for Energy in a Dry Year
<b>Energy Adequacy</b>	Having enough generating plant (and the fuel to run it) to meet demand (MWh) over the defined period to which the phrase is applied
<b>Energy Call Option</b>	A contract which gives the holder of the contract the right (but not the obligation) to require the seller of the contract to provide it with a specified amount of energy, over a specified period, at a specified price

<b>Energy Margin</b>	The difference between the expected amount of energy that can be supplied, and expected demand, expressed as an amount of electricity or as a percentage
<b>FDI</b>	Foreign Direct Investment
<b>GPS</b>	Government Policy Statement on Electricity Governance
<b>Grid Exit Point (GXP)</b>	A point of connection where electricity may flow out of each grid owner's network
<b>GWh</b>	Gigawatt hour, a million kilowatt hours
<b>Huntly</b>	The coal plant owned and operated by Genesis Energy in Huntly, Waikato
<b>Installed Capacity mechanisms (ICAP)</b>	Installed capacity mechanisms that are used in several eastern US markets (PJM, New York and New England). These mechanisms are entirely separate to the energy markets. Obligations are imposed on each purchaser (known as a load serving entity or LSE) to procure installed capacity 'tickets' (which may include own generation) in proportion to their contribution to peak load
<b>kWh</b>	Kilowatt hour, the basic unit of electrical energy
<b>Last Minute Intervention</b>	A type of intervention designed to ensure security of supply in which the Commission waits until after the last moment at which the market could provide additional capacity or energy to meet a Security Standard, and then intervenes by procuring reserve energy or capacity using an option that can be delivered quickly, such as an diesel-fired open cycle gas turbine on a pre-consented site
<b>Levy</b>	The levy the Commission makes on all wholesale market purchases to cover the cost of the reserve energy Arrangements
<b>Load Serving Entities (LSE)</b>	Retailers and major users
<b>Long Run Marginal Cost (LRMC)</b>	A generator's costs incurred in generating of the next unit of electricity over a period of time in which all costs are variable
<b>Market Failure</b>	In this context, a situation in which the market fails to provide the socially optimal level of security of supply
<b>M-co</b>	The Marketplace Company, operator of the New Zealand electricity wholesale market prior to the formation of the Electricity Commission
<b>MED</b>	Ministry of Economic Development
<b>Minzone</b>	A defined level of aggregate hydro storage, below which the current reserve energy Arrangement requires that action be taken to provide reserve energy, so reducing the risk that the energy security of supply standard will be breached. As hydro storage levels drop due to lack of rainfall, the risk of electricity shortage increases. If storage falls to the Minzone line, it means that from that point there is at least one annual inflow sequence out of the 74 on record which, if repeated, could result in demand restraint being required if no action is taken
<b>Morrison &amp; Co's Enhanced Reserve Energy Proposal</b>	A possible intervention in the market to ensure security of supply, proposed by Morrison & Co. Involves the Commission running a tender for reserve energy once a trigger point (defined in terms of the Minzone) has been reached
<b>MWh</b>	Megawatt hour, a thousand kilowatt hours
<b>NERA</b>	National Economic Research Associates
<b>NETA</b>	New Electricity Trading Arrangements
<b>New Electricity Trading Arrangements</b>	The current design of the England and Wales wholesale electricity market
<b>Optimal Level of Security of Supply</b>	The level of Security of supply that maximises economic welfare by achieving the optimal balance between the costs of non-supply and the costs of increased security

<b>Over-build of generation</b>	A situation in which an excessive amount of generation is built, caused by procurement of excessive energy call options relative to what is needed to achieve the security of supply standard
<b>PA</b>	PA Consulting Group
<b>Peak Adequacy</b>	A situation in which the capacity of generating equipment intended for operation during the hours of highest daily, weekly or seasonal loads is sufficient to meet peak demand at the desired level of security of supply
<b>Periodic Failure</b>	A type of market failure, whereby market participants might on average provide sufficient resources to achieve the socially optimal security of supply (allowing for all contingencies), but are prone to error or other problems that lead to new plant being delivered late at times, creating periods in which security of supply is below the optimal level
<b>Policy</b>	Electricity Commission's security of supply policy described in the Government Policy Statement on Electricity Governance
<b>Price Adder</b>	An additional payment to generators that offer to generate or are dispatched in a particular trading period, i.e. a payment for provision of real time capacity
<b>Price Protection</b>	An aspect of security of supply policy that aims to limit the price of energy at times of possible shortage
<b>Regime</b>	The reserve energy regime as set out in the Government Policy Statement on Electricity Governance
<b>Resource</b>	Something required to meet electricity demand. A generic term which includes Capacity and Energy
<b>Relative Security of Supply</b>	A level of Security of Supply defined in terms of a probability that the specified security level will be met
<b>Relative storage level</b>	A level of hydro storage defined relative to the 10 <sup>th</sup> percentile storage level for that time of year
<b>Reserve energy</b>	Energy procured or mandated to be procured in pursuit of Security of Supply objectives
<b>Reserve Energy Needs Assessment</b>	The 'Reserve Energy Needs Assessment', prepared by Concept Consulting Group, October 2005
<b>Resource Adequacy</b>	Both peak adequacy and energy adequacy. Generally, a situation in which there are enough Resources to meet demand with the desired Security of Supply
<b>Review</b>	This independent review of reserve energy arrangements
<b>RMA</b>	Resource Management Act
<b>RSL</b>	Relative Storage Level
<b>Security of Supply</b>	In this report means Relative Security of Supply, unless otherwise specified
<b>Short Run Marginal Cost (SRMC)</b>	A generator's costs incurred in generating the next unit of electricity over a period of time in which capacity is fixed
<b>Spot Prices</b>	Per kilowatt hour prices paid for wholesale energy in the wholesale market
<b>Stakeholders</b>	People and organisations with an interest in, or influence over, the performance or the electricity market and the level of Security of Supply
<b>Strike Price</b>	With reference to a Call Option, the price at which the holder of the option has the right to buy energy from the seller of the Call Option
<b>Sunk Costs</b>	A cost incurred in the past that will not be affected by any present or future decision
<b>Supply Insecurity</b>	Failure to achieve desired levels of security of supply

<b>Systematic Failure</b>	A type of market failure, whereby the market, on average and in general, fails to deliver adequate resources to achieve the socially optimal security of supply
<b>Type 1 Error</b>	The chance of accepting the alternative hypothesis when the null hypothesis is actually true
<b>Type 2 Error</b>	The chance of accepting the null hypothesis when the research hypothesis is actually true
<b>TWh</b>	Terawatt hour, a thousand gigawatt hours
<b>Un-served energy</b>	Energy demand that is not supplied as a result of Demand Restraints
<b>USE</b>	Percentage of Un-served Energy
<b>Value of Lost Load</b>	The economic loss suffered as a result of an unexpected loss of electricity supply, expressed in \$ per kWh lost
<b>VoLL</b>	Value of Lost Load
<b>WEMDG</b>	Wholesale Electricity Market Development Group

## Executive Summary

This report presents the findings of Castalia’s independent review (Review) of the reserve energy arrangements. The Arrangements consist of the reserve energy regime (Regime) as set out in the Government Policy Statement on Electricity Governance (GPS), and the Electricity Commission’s (Commission’s) security of supply policy (Policy), which implements the Regime.

The Review aimed to answer the following key questions:

- What is the optimal security of supply standard for New Zealand?
- Is it likely that the market will deliver this level of security by itself?
- How have the current reserve energy Arrangements worked?
- What other approaches to achieving the desired security of supply should be considered, and how do they compare to the current Arrangements?

This report answers the above questions and provides specific recommendations on how the Arrangements can be improved. Below we briefly summarise our main recommendations, while subsequent sections provide a more detailed summary of our analysis and resulting recommendations.

We recommend the following:

- That the security of supply standard be changed from ensuring no demand restraints (either voluntary conservation or forced rationing) are required in a 1-in-60 dry year, to ensuring that the energy margin does not decline below a minimum desired amount
- Further detailed work should be undertaken to estimate the desired energy margin. We estimate the desired annual margin to be approximately 15 percent (this equates to ensuring no demand restraints are needed in a 1-in-20 dry year, rather than the 1-in-60 dry year used for the current standard)
- The Arrangements should not at this stage introduce mechanisms that involve energy adequacy hedges, as there is no evidence to suggest that the market will fail to deliver the desired level of security of supply
- However, given that there is no conclusive evidence to rule out the **possibility** of the market not providing sufficient security of supply, the Commission should retain its ‘watch dog’ role of monitoring the security of supply situation and, if needed, procuring and dispatching reserve energy (by which we mean either generation, or contracted demand response) to ensure the security of supply standard is met
- If, over time, evidence emerges that the market is failing to provide adequate security of supply (which will lead to the Commission needing to regularly procure additional reserve energy), the Commission should (as currently provided for in the Regime) recommend to the Minister that a comprehensive solution be introduced based on energy adequacy hedge mechanisms
- Given that there appear to be no better alternatives to the current levy arrangements, these should be retained (despite their shortcomings)

- The relative scopes of the Regime and the Policy should be amended to provide more flexibility for the Commission to achieve the desired security of supply outcomes:
  - The Regime should focus on:
    - Defining an operational standard of security of supply (the energy margin) that should be achieved, and
    - Defining the Commission’s powers to intervene in the market
  - All other operational detail should be left for the Commission to define as part of the Policy
- The current Policy can be improved by:
  - The Commission providing better information that is more tailored to the relevant audience. Market participants should be given more information on the assumptions behind and workings of the Minzone analysis, while the general public needs simpler and clearer information on the actual level of risk to security of supply at any point in time
  - The Commission ensuring that the Policy sets out a clear trigger for the procurement of any additional reserve energy (generation or contracted demand response), and the detailed process that will be followed if such procurement is triggered, and
  - Changing the Whirinaki dispatch strategy to only run the plant at Short Run Marginal Cost (SRMC). Any additional reserve energy that may be acquired in the future should also be dispatched at SRMC.

### **Defining the Optimal Security of Supply Standard**

We know that absolute security of supply is not a sensible objective. Massive redundancy in plant and fuel supplies would be needed. But what level of security should we aim for?

From an economic point of view, the optimal level of security of supply is that which minimises the total combined cost of un-served energy and security of supply mechanisms (we refer to ‘un-served energy’ or ‘demand restraints’ as including any voluntary conservation or forced rationing).

The risk and extent of outages can be reduced, at a cost, by adding generation to the system, or paying customers to reduce demand—both of which create additional energy and capacity in the system. At the margin, one would incur the cost of improving security of supply until the cost of improving it further is equal to the cost of the expected outages. Going beyond this point would mean that the cost of avoiding the outages is higher than the avoided cost of the outages occurring.

The optimal level of security of supply minimises the total cost of supply and demand restraints. At the minimum total cost, the marginal cost of demand restraints will equal the marginal cost of increasing energy security of supply.

When we estimate the economically optimal **level** of security of supply, we find that it is likely to:

- Involve an expected level of un-served energy each year of around 0.05 percent, which
- Equate to a probability of demand restraint around 1-in-20, and

- Imply an optimal annual energy margin of about 15 percent.

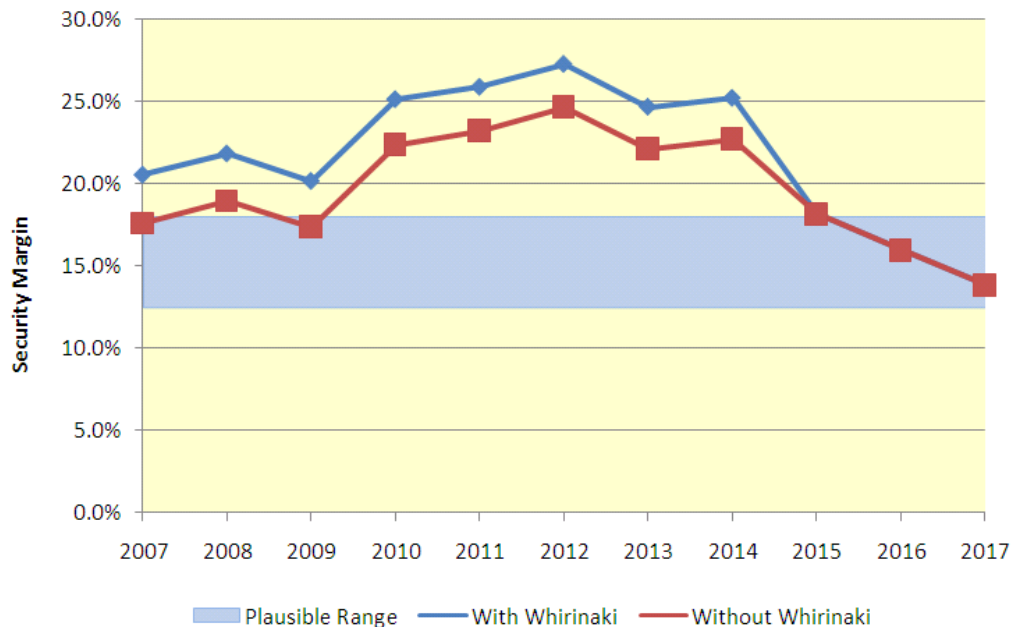
Given the uncertainties in the assumptions behind these estimates, we are at this stage just identifying a plausible **range** for the optimal level of security of supply. For example, the likely range for the optimal probability of demand restraints is from 1-in-11 to 1-in-35 and the range for the optimal energy margin is 12 percent to 17 percent. However, our estimated range for the optimal security of supply is consistently lower than the current Arrangements aim to achieve.

The 1-in-60 standard appears to require restricting expected annual un-served energy to about 0.014 percent, requiring an annual energy margin of 19 percent.

On the other hand, our range for the optimal energy margin is broadly consistent with the historical 7 percent ECNZ dry year security margin. That standard required energy supply to be 7 percent above forecast demand, after assuming a 15 percent loss in hydro supply. At that time, average hydro supply was close to 70 percent of the total so the convention provided a 17 percent gross annual energy margin.<sup>1</sup>

We stress that these are preliminary calculations designed to illustrate the methodology and inform the Commission’s thinking. The precise energy margin should be calculated by simulation to allow fully for outages and operational constraints.

**Figure 1: Expected Gross Energy Margins**



Source: Castalia

### Achieving the Desired Standard

Will the market deliver the desired standard, and if not, what options are available for correcting the market failure? By ‘market failure’ we mean the failure of the market to deliver an appropriate level of security of supply, noting that this is different from the textbook definition of the term.

<sup>1</sup> 7% + 15% of 70%

Our analysis of forward generation investment commitments and plans indicates that some form of market failure cannot be ruled out. On reasonable investment projections over the next ten years, the expected gross energy margin for the New Zealand electricity market may fall below plausible estimates of the optimal level of reserve margin, save for the availability of energy from Whirinaki. While we cannot dismiss the possibility that Whirinaki is itself crowding out some commercial investment, we find that with more conservative assumptions, the expected gross margin may be too low even **with** Whirinaki. However, as noted by some stakeholders during consultation, the decline of the energy margins after 2014 may simply reflect the fact that some generation projects may simply not have been revealed to the market yet. Those submitters also noted that the decline in forecast energy margins assumes that some plant will be decommissioned before replacement units have been put in place—which is unlikely to happen in practice.

Markets may fail to deliver adequate resources to provide the socially optimal level of security of supply for a variety of reasons. Different causes of market failure would lead to a different frequency and magnitude of problems. The choice of the appropriate corrective mechanism will, in turn, depend on that frequency and magnitude. However, while it is useful to classify types of market failure in principle, we find that at present there is simply no information to identify in practice what may be causing potential problems, and how serious those problems are.

Hence, we need to develop a framework for deciding on an appropriate intervention policy recognising this uncertainty. We consider the full range of interventions which have been proposed by various stakeholders. As a reference case, we examine the relative costs and benefits of adopting different interventions for each type of market failure, if the type of market failure were known.

We propose that without certain knowledge about the type—or even the existence—of market failure, corrective measures should aim to minimise the sum of errors: the error of intervening too much when less intervention is appropriate, and the error of not intervening enough when greater intervention is optimal. This logic translates into a ‘watch dog’ approach: the Commission should remain ready in case market failure becomes evident. The Commission should stand ready for a last minute procurement of further energy from contracted demand response or diesel-fired open cycle gas turbine capacity in the event it becomes obvious that, given lead times, sufficient market investment would not be in place before it becomes too late to commission such capacity.

We now expand on this analysis.

### **Type of Market Failure**

In principle, it is important to distinguish between different kinds of market failure because the best policy response will depend on a clear diagnosis of the problem. For example, if the issue is specifically that the market does not deal well with the most severe dry years, then we would consider a response targeted to this specific failure. It is possible that the Whirinaki contract has already solved that problem for now and into the future. On the other hand, if the market failure is more comprehensive, so that there is a pervasive risk to security of supply, then more fundamental additions to the market may be needed.

In this context, we suggest that market failure could fall into three broad categories:

- **Contingency-specific failure:** The market might not provide optimally for some specific contingencies, such as very dry years, but generally delivers sufficient resources to meet demand in all other circumstances.

The intuition is that markets do not deal well with low probability events. This may be exacerbated if the private loss to market participants from lost load in extreme circumstances is less than the social loss.

- **Periodic failure:** Market participants might on average provide sufficient resources to achieve the socially optimal security of supply (allowing for all contingencies) but are prone to error. For example, as load grows, investors will add capacity in time to meet additional demand and to maintain adequate security of supply, but occasionally, unexpected construction delays will lead to periods of a higher risk of shortages.

In themselves, errors are not a sign of market failure. In this case, a failure might arise if there is the difference between the private and social cost of the error. For example, while both investors and consumers benefit if new capacity is brought in just in time to meet load growth, the cost of delay to investors might be lower than it is to consumers.<sup>2</sup> The particular concern is that the period of delay could coincide with a dry year. In other words, if the private and social costs were perfectly aligned, the errors may be less frequent, as market participants incorporate the risk of delays into their plans and do not wait too long to bring on new capacity.

- **Systematic failure:** It may be that on average the market fails to deliver adequate resources to achieve the socially optimal security of supply. Systematic failure would not mean **no** market investment, but that investment is consistently late relative to load growth. The result would be that the security margins are too low even in relatively normal years, let alone in extreme dry years.

### Intervention Options

There is a wide range of options proposed for New Zealand conditions, but these models tend to share core features. The table below summarises the main features of various proposals and groups them according to their main characteristics. These characteristics include:

- **The degree of centralisation of procurement**—At the centralised end of the spectrum, the Commission identifies the need for reserve energy and undertakes all procurement. At the decentralised end, the Commission sets the security of supply requirements, but load serving entities are free to procure as they see fit to meet those requirements
- **Whether the intervention applies to ‘missing energy’ or all load**—In the former case, the Commission identifies the gap between the desired security of supply standard and what the market is delivering, and fills the gap. In the latter, the Commission procures Energy Adequacy Hedges for all load. We use the term Energy Adequacy Hedge to describe generically a range of possible hedge instruments, such as forward contracts for energy (contracts for differences), energy call options and actual ownership of physical plant and fuel<sup>3</sup>

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<sup>2</sup> Spot prices might not rise fully to shortage levels during periods of demand restraints but may be high for sustained periods while there is a risk of shortages. It is not clear that there is any lack of incentives from the spot market.

<sup>3</sup> There is a serious debate to be had about whether financial hedges are enough, or whether they need to be physically backed. If financial penalties were adequate to cover the social cost of non-performance, then purely financial penalties might be enough. But, to make financial penalties at these levels enforceable would require huge performance bonds or capital adequacy requirements, which might not be enforceable. Hence, purely financial

- **Whether the intervention provides protection from high spot prices as well as additional energy**
- **How the costs of the intervention would be recovered.**

Overall, various proposals converge to four options:

1. **Current Arrangement:** The current policy of procuring **missing** energy as needed, perhaps with minor changes. This also includes the **watch dog** option, under which the Commission would stand ready to intervene at the last minute if it becomes necessary, but would be ready to move to more comprehensive options if it becomes obvious that frequent and significant intervention is required.
2. **Procure All Hedges:** Centralised tendering for Energy Adequacy Hedges covering all energy. This will involve rating all available generators for their capability to produce energy in a dry year (or in other relevant events, such as a windless year).
3. **Procure All Hedges with Opt-out:** Centralised tendering for Energy Adequacy Hedges for the proportion of load that load serving entities have not already hedged themselves. Those who choose to self-insure would need to demonstrate they are holding sufficient firm energy hedges to meet expected load in a dry year (or other relevant eventuality).
4. **Market Augmentation:** A completely decentralised approach built around tradable obligations to hold Energy Adequacy Hedges. All load serving entities would be required to hold sufficient Hedges to meet their own expected load, or face significant penalties.

Table 1 gives further details.

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hedges might not provide comfort to the public or politicians, who might perceive the financial instruments as providing a way to gamble on New Zealand's energy security, without legally requiring physical plant and fuel. For these reasons most participants supported a 'physical' backing of the financial instruments, and we agree. However, as we explain below, these distinctions turn out to be not material to our recommendations.

**Table 1: Range of Potential Interventions to Ensure Adequacy**

	Description	Degree of centralisation	Proponent	Levy	Price hedge?
<b>1. Current Arrangement</b>	The Commission procures dry year call option on <b>specific energy quantity</b>	Centralised procurement	Existing reserve energy scheme	Universal charge, effectively on all consumers	No, apart from some price capping effect
<b>2. Procure All Hedges</b>	The Commission procures dry year Energy Adequacy Hedge for <b>all load</b>		M-co		Yes
<b>3. Procure All Hedges with Opt-out</b>	The Commission sets the Energy Adequacy Hedge requirement for <b>all load</b> , procures Energy Adequacy Hedge for <b>remaining un-hedged load</b>	Centralised procurement with opt out	Morrison & Co	Commission on-sells the hedges and recovers the net cost from un-hedged load	Yes, to the third party buyers of the hedges
			Contact/NERA	Those who opt out and self-provide cover their own costs. The Commission levies un-hedged load	Yes
<b>4. Market Augmentation</b>	Retailers and major users are required to procure Energy Adequacy Hedges for <b>all their load</b>	Decentralised procurement	WEMDG/CRA	No levy powers	Yes

Source: Castalia

### Intervention Policy

If we knew for sure what kind of market failure we were facing, the conclusions on interventions would be fairly obvious:

- If the failure is contingency specific, the current Arrangements providing a relatively low cost solution (with Whirinaki possibly already solving the problem and only monitoring being required going forward), and there is no benefit from changing
- If the market failure is periodic, the current arrangements may still be the least cost solution, as the risk of overbuild and additional transactions costs

probably would outweigh the additional benefit of solving this kind of problem through hedge requirements

- If the market failure is systematic, the current arrangement is likely to become costly and distorting. It would then be worth incurring the additional transactions costs of implementing more comprehensive hedge based intervention options.

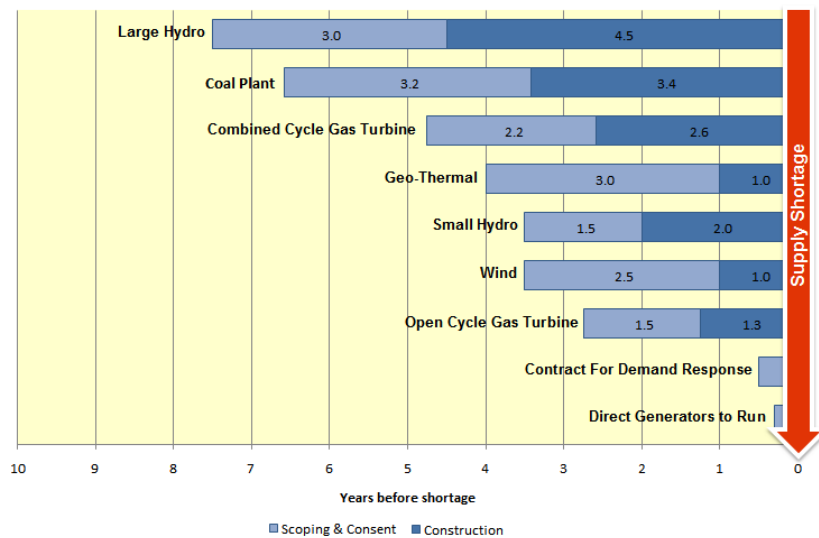
However, we believe there is insufficient information to conclude what the exact nature of the market problem is, or indeed if there is a problem. In part, this is because the current policy settings have not been around for long enough to draw conclusions. In part, it is because we have no way of reliably distinguishing between firm investment plans and broad intentions.

It would be a mistake to pretend that problems can be identified with certainty. Rather, it is important to recognise uncertainty, and to build the Regime on effectively addressing that uncertainty. This has two implications:

- First, the Regime needs to evolve as new information becomes available. Hence, it is important to identify markers which should prompt specific actions, and
- Second, the Regime needs to recognise the likelihood of errors. The Regime should aim to minimise the overall cost resulting from such errors.

We conclude that because the Commission is able to act faster than the market participants (see the chart below), the current regime allows it to delay intervention as long as possible, and only to intervene when it is fairly obvious that intervention is required. If the market failure is specific to the dry year problem, then no further intervention is likely to be needed, and the only cost would be the cost of on-going monitoring. Since Whirinaki is already built, and its cost is sunk, the historic distortion to the generation mix associated with it is no longer relevant.

**Figure 2: Lead Times for New Reserve Energy**



Source: Castalia

If the problem is periodic market failure, the Commission will have an option of deciding the best way to deal with the particular market errors which may emerge. For example, if the problem is caused by construction delays, contracted demand response may be the least cost option. At worst, there may be cause to build further open cycle gas turbine capacity, which would somewhat increase the cost of distortion to the generation mix.

If the market failure turns out to be sustained and systematic—unlikely as it is—this will become obvious due to intervention being needed for reasons other than plant delays. At that point, the Commission will have the option of introducing a more comprehensive solution.

All comprehensive solutions (both centralised and decentralised hedge mechanisms) appear to carry a risk of promoting excess capacity. The mechanisms require the Commission to impose requirements on the market sufficiently far into the future so that market participants are able to build various kinds of additional capacity if it is needed. If the Commission wants to avoid distorting the generation mix, the effective lead time needs to be long-enough to accommodate all technology options, such as seven or more years for large hydro.

Acting this far in advance, the Commission will need to take account of the likely error in forecasting load. Since the Commission will no longer have an option of last minute *ad hoc* intervention, it may be more concerned about the risks of ‘under-shooting’ security of supply that far into the future, rather than ‘over-shooting’. Hence, it will likely be risk averse, and will tend to promote over-build.

So, if the market failure is specific to the dry year, comprehensive solutions will have imposed over-build and high transactions costs for no particularly good reason, as that problem has most likely been fixed and any distortion associated with Whirinaki is now a sunk cost. If the market failure is periodic, the transactions cost and the cost of overbuild associated with comprehensive options is again higher for that kind of problem than the mild distortion to the generation mix. Comprehensive measures are appropriate for sustained market failure, but we always have an option to introduce them if the sustained failure is revealed.

Overall, since we do not know what kind of failure—if any—we are dealing with, the current regime, with enhancements, is the best path forward.

### **Improving the Current Arrangements**

Having recommended the continuation of the general approach behind the current Arrangements, we now turn to possible specific improvement for the Regime and Policy.

#### **Clarifying Scope of the Regime and Policy**

A clear delineation is needed between the respective roles of primary legislation, the Electricity Act 1992 (the Act), the GPS (the Regime) and the practical implementation of both (the Policy). In our view, legislation should define, at a principle level, the objective that must be achieved by the Commission. The Regime should then translate the legislative objective into clear regulatory settings. These settings should:

- Explain how the high-level legislative objective should be interpreted by providing more detail, including quantifying the objective where possible
- Define and set clear boundaries on the powers that the Commission can use to achieve the objective (including any ability to impose costs on market participants either directly or by compelling them to act in a certain way), and

- Leave all other details to be defined in the Policy, thus allowing the Commission maximum operational flexibility subject to the two bullet points above.

This approach will help to ensure that:

- The regulatory objective is clear to the Commission and market participants alike
- The Commission, as an expert regulatory body, is given appropriate operational flexibility to achieve the regulatory objective in the most effective way,<sup>4</sup> and
- Market participants have clarity and certainty with respect to the sort of costs the Commission can impose in order to achieve the objective, without the need for additional regulations to be introduced by Government.

The current framework differs from this approach because the Regime, in translating the legislative objective, goes much further than simply defining a quantitative objective and the boundaries of the Commission's powers. The more detailed, operational aspects of the Arrangements, which are currently set out in the Regime, should therefore be delegated to Policy level. The Commission could then define and review these detailed aspects as needed and, if warranted, make changes to the Policy, without the need for Government involvement to change the Regime. This approach would help create a more stable investment environment for market participants.

### **Levy Mechanism**

We recommend that the existing levy mechanism should be retained for the present assets. If the Commission finds that it has to intervene again to buy more reserve energy, we recommend that this cost also be recovered by a universal levy. We anticipate that if this further intervention happens, the Commission will move to providing or requiring energy adequacy hedges. In all the proposed schemes in which the Commission procures energy adequacy hedges, costs are recovered just from those on whose behalf the Commission has acted.

### **Effectiveness of Minzone**

We conclude that there is some risk of thermal plants not being dispatched in the existing Minzone. It is likely that this reflects the conservative nature of the Minzone. By this we mean that the Minzone is based on an absolute security standard, rather than an economic security standard, and a limited set of specific inflow sequences, rather than the overall probability of a set of inflow sequences. Hydro-generators' own assessments of the risk of energy shortages may be less conservative, and this may lead hydro-generators to submit bids that in some cases result in their plant being dispatched ahead of thermal plant, even when the Minzone has been reached.

This risk would be lowered if the security of supply standard were reduced toward its optimal level. Even at the current 1-in-60 level, spot prices during the dry part of 2006 were enough to dispatch all thermal plant except Whirinaki.

There is some risk that dispatching Whirinaki at the Minzone boundary when spot prices are below 20 c/kWh would displace some thermal generation and hence not conserve

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<sup>4</sup> We are aware that the Electricity Commission already has the power to require market participants to contract in particular ways.

water, but we cannot resolve this issue without some experience of actual Minzone prices.

Stakeholders want more information on the Minzone calculation but this will be limited by the Commission's need to protect commercially sensitive information that forms an important input to the calculation.

### **Further procurement**

There is some scope for improving the process for any further procurement of reserve energy. However, given our recommendation that direct Commission procurement should not be a long term solution, the improvements to the procurement process relate mostly to enhancing the Commission's ability to secure contributions to energy security of supply as quickly as possible.

The trigger for considering the procurement of additional reserve energy should be based on the efficient level of security of supply discussed earlier.

We recommend that the trigger for additional procurement should be expressed in terms of a desired energy margin. Our preliminary calculations indicate that the minimum desired energy margin would be between 12 and 17 percent. We recommend that the Commission should procure additional reserve energy when it becomes clear that the actual energy margin will fall below the minimum desired level.

To give the market and other stakeholders certainty with respect to how additional reserve energy will be procured, a clear definition of the actual procurement process is required. Either diesel- or gas-fired peaking plant (similar to Whirinaki) or contracted demand response are likely to be the most appropriate forms for any additional reserve energy required in the future. The Commission should therefore be able to define in advance the process and requirements for any future reserve energy tender. Separate requirements could be defined for demand response and reserve generation.

Pre-consenting sites for reserve generation (directly or via an option) would help reduce lead times for commissioning the plant. This would allow the Commission more waiting time to see if the market will respond, thereby reducing any distortion to the market. Pre-consenting will carry some costs because Resource Management Act procedures require any proposed project to be defined in quite some detail. The plant specification and consents may also need to be changed as technologies change.

### **Improved Information**

While it might seem that a compulsory framework for information gathering may be more robust, introducing such a framework would be costly and it is not apparent that substantial incremental benefits would result (especially given difficulties in enforcing some aspects of information provision). Given that the Commission is generally satisfied with the quality of information provided so far, it is appropriate to retain the voluntary approach. This decision should be revisited from time to time, especially if the quality of information provided appears to deteriorate.

Discussion with stakeholders also suggested that perceptions of actual risk to security of supply at any point in time could be assisted by making it more obvious that the Minzone boundary records where the risk of some demand restraint reaches 1-in-60, not where conservation campaigns are required. Given the differing preferences of stakeholders with respect to the level of detail they would like to see disclosed, the Commission should also specifically target some publications for lay-people and others for market participants.

# 1 Introduction

This report (Report) presents the findings of Castalia’s independent review (Review) of the reserve energy arrangements. The Arrangements consist of the reserve energy Regime as set out in the GPS, and the Commission’s security of supply policy, which implements the Regime.

The Review aimed to answer the following key questions:

- What is the optimal security of supply standard for New Zealand?
- Is it likely that the market will deliver this level of security by itself?
- How have the current reserve energy Arrangements worked?
- What other approaches to achieving the desired security of supply should be considered, and how do they compare to the current Arrangements?

The remainder of this introductory Section provides relevant background information, outlines the process followed for the Review and discusses how the Review has been structured.

## 1.1 Background to the Reserve Energy Arrangements

The New Zealand electricity system relies heavily on hydro-electric power stations. This reliance, combined with the small amount of hydro storage in the system and New Zealand’s geographical isolation, leaves the system exposed to risks of electricity shortages during prolonged periods of low inflows to the hydro lakes (dry winters).

In 2001 and 2003, low hydro inflows resulted in sustained high spot prices in the wholesale electricity market. In both years, nationwide conservation campaigns and (in 2001) temporary reductions in transmission security were used to ensure supply was maintained. Since electricity shortages (or even a significant risk of shortages) could seriously damage the economy, in 2003 the Government decided to intervene in the electricity market to promote greater security of supply. In May 2003, the Government established the Commission as the body responsible for electricity governance, and mandated the Commission to develop and implement reserve energy Arrangements.

The key changes implemented at the time included:

- Government investment in a reserve energy power station at Whirinaki (commissioned on 1 June 2004)
- Introduction of the Regime on 14 September 2003, and
- Vesting the responsibility of implementing the Regime with the newly-formed Commission in October 2004.

The Regime was outlined in a draft Government Policy Statement on Electricity Governance (draft GPS) released on 14 December 2003. The draft GPS provided detailed guidance on how the Government expected the newly created Commission to implement the Regime. Although the draft GPS has since been finalised and then revised several times, the parts setting out the Regime have remained largely unchanged.

## 1.2 Basis and Scope for the Review

The Regime itself requires that this Review take place. The Review is limited to the reserve energy Arrangements, and does not include reviewing the Act (the Act provides

the statutory under-pinning for the Regime). Nor does the Review address security of supply issues related to transmission investments.

### **1.3 Process for the Review**

Castalia was appointed as the independent reviewer on 29 November 2006. On 8 December 2006 Castalia released an Issues Paper<sup>5</sup>, which was used to facilitate information gathering through interviews with stakeholders (22 in total) and written submissions.

On 12 March 2007, Castalia released and invited submissions on a Consultation Paper<sup>6</sup> that set out our preliminary analysis and draft recommendations. Written submissions were received from 11 stakeholders: Contact Energy, Genesis Energy, Grey Power, Meridian Energy, Major Electricity Users Group, Mighty River Power, Ms. Molly Melhuish, Orion, Transpower, TrustPower and Vector.

Castalia also held a public hearing on 24 April 2007 to discuss the analysis and draft recommendations in the Consultation Paper, as well as issues raised in submissions. We would like to thank all stakeholders who provided feedback and comments throughout the Review.

The Commission will now follow its own process, which may include additional consultation, to consider our report and consequently make recommendations to the Minister of Energy.

### **1.4 Structure of this Report**

The analysis in this report focuses mainly on whether the Regime, as currently set out, is optimal and how it can be improved. We start by summarising how the current reserve energy Arrangements work, and their legal and policy basis (Section 2). We then proceed to define the optimal security of supply standard. This has three steps:

- Defining security of supply, and the various causes of insecurity of supply (Section 3)
- Calculating the optimal security of supply (Section 4), and
- Recommending a workable security of supply standard (Section 5).

We then turn to consideration of how best to achieve a given security of supply standard. We review the various options that have been proposed during consultation, and group them into a number of categories. We evaluate the options against the criteria of effectiveness and cost. We conclude that continuation of the current approach for a period may be the best option, since it safeguards against risk while allowing new information to emerge on whether or not the security of supply problem is serious enough to warrant a more fundamental intervention.

Given this preliminary recommendation it becomes important to consider improvements that can be made within the current regime. We discuss the future of the levy arrangements, the Minzone assumptions regarding the point of dispatch of all thermal plant, the Commission's dry year information program, and the concern about conflicts of interest in the Commission's operation of a generation plant.

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<sup>5</sup> [http://www.castalia.fr/SITE\\_Default/x-files/21092.pdf](http://www.castalia.fr/SITE_Default/x-files/21092.pdf)

<sup>6</sup> [http://www.castalia.fr/SITE\\_Default/x-files/22631.pdf](http://www.castalia.fr/SITE_Default/x-files/22631.pdf)

### Box 1.1: Review of International Experience

To help consider the security of supply issues for New Zealand, we sought to examine the experience and approaches of other countries with similar issues. In our search, we looked for countries with similar physical system characteristics to that of New Zealand. The two main physical characteristics that distinguish the New Zealand system from most other countries are:

- **Geographic Isolation**—New Zealand has no interconnection with other countries and cannot purchase power from other countries to overcome energy shortfalls, and
- **Substantial Exposure to Fuel Risk**—A large part (56 percent on average) of New Zealand’s generation comes from hydro sources. Our hydro stations have limited storage capacity (approximately 10 percent of annual demand). In dry periods, inflows can be reduced by around 20 percent, requiring substantial thermal backup.

These characteristics were used as criteria when selecting potential comparators. However, very few countries combine both these factors, so we included countries that have one or the other of the characteristics. The comparators selected were Iceland, Japan, Norway, Brazil and Chile.

Of course, it would be ideal if comparator countries also had similar market structure to that of New Zealand. However, this would narrow the pool of comparators to one country—Norway. While Iceland also has a newly established wholesale electricity market for contracts, it does not have a spot market. There is no single model from which we can learn. Rather, it is a question of gleaning relevant lessons from a range of cases.

We also added the United Kingdom as a comparator that is an island nation with a well-developed electricity market and a recognised security of supply issue during a cold winter. The table below summarises the key characteristics of comparator countries selected:

Country	Substantially exposed to fuel risk?	Has no or very limited interconnection to other countries?	Percentage of Hydro Generation
Iceland	Yes (hydro)	Yes	81%
Japan	Yes (fossil fuel imports)	Yes	10%
Norway	Yes (hydro)	No	99%
Brazil	Yes (hydro)	No	84%
Chile	Yes (hydro)	No	43%
United Kingdom	No	Yes	1%

Our full analysis of comparator countries is set out in Appendix A. Further boxes throughout this report summarise some of the key insights from this analysis.

## 2 The Current Arrangements

This section describes how the current reserve energy arrangements work now, and the legal and policy instruments which underpin the arrangements.

### 2.1 Overview of how the Reserve Energy Arrangements Work Now

In this section we provide a little history and a simplified summary of the operation of the Arrangements.

#### 2.1.1 The origin of the 1-in-60 standard

Prior to 1992, the New Zealand system was operated by ECNZ, which used a 1-in-20 dry year planning standard. The standard required that the system be operated in such a way that forced supply restrictions resulting from the exhaustion of hydro storage were not expected to occur unless inflows are below a 1-in-20 dry year level (thus accepting a five percent probability of shortage).

In 1992, a drought resulted in very low South Island hydro storage levels. Eventually, voluntary savings of around 10 percent were required to avoid forced rationing. The Electricity Shortage Review Committee, set up to investigate the shortage, recommended that the 1-in-20 standard be temporarily raised to a 1-in-60, pending further analysis and consultation with the industry. The 1-in-60 standard was effectively equal to a 'worst of the past' standard, as only 60 historical inflow records were then available.

The substantial increase from 1-in-20 to 1-in-60 was easily achievable at the time because soon after 1992, more than adequate capacity existed to satisfy demand comfortably until 1999. Therefore, the only incremental costs of increasing the standard were related to fuel, rather than capital costs of new plant. The Government accepted the Committee's recommendation and instructed ECNZ to operate the system to a 1-in-60 standard.

Concurrently, during 1992 and 1993, the Government commenced significant reforms of the electricity sector. These included creating a competitive wholesale electricity market and separating ECNZ into various smaller entities, with a final split occurring in 1998.

ECNZ's implicit obligation to manage the system to a 1-in-60 dry year standard ceased in 1996. At that point, responsibility for managing dry year risk was shifted to all buyers and sellers in the wholesale electricity market. The Government stated its intention not to intervene if either buyers or sellers did not procure adequate dry year protection. At a principle level, the Government noted that it expected dry year and other supply risks to be managed in such a way as to minimise overall costs to the New Zealand economy.

In 2001 and 2003, low hydro inflows resulted in sustained high spot prices in the wholesale electricity market. In both years, nationwide conservation campaigns and (in 2001) temporary reductions in transmission security were used to ensure supply was maintained. Since electricity shortages (or even a significant risk of shortages) could seriously damage the economy, in 2003 the Government decided to intervene in the electricity market to promote greater security of supply. In May 2003, the Government established the Commission as the body responsible for electricity governance, and introduced the Regime, including a 1-in-60 security of supply standard.

### 2.1.2 Ensuring the 1-in-60 standard is met

To ensure that the 1-in-60 security of supply standard is met—meaning that the chance of requiring conservation campaigns or worse in dry periods has to be kept to less than 1-in-60—the Regime requires the Commission to:

- Monitor the security of supply situation and provide relevant information to the market (the aim is to encourage the market to adequately manage security of supply issues without the need for intervention)
- As needed, dispatch the 155 MW Whirinaki plant—currently the only source of reserve energy (Whirinaki was built by the Government prior to the introduction of the Regime and contracted to the Commission for use as reserve energy)
- Regularly assess the need for additional reserve energy to be procured. If such a need is identified—contract for additional reserve energy, and
- In carrying out its duties, minimise distortions to the normal operation of the market.

The Minzone is the main tool used by the Commission to monitor security of supply. Inputs to the Minzone include historical hydro inflow sequences, transmission constraints, demand forecasts and voluntarily provided information on available generation. This information is used to calculate, for any point in time, the minimum amount of hydro storage required to ensure that security of supply is maintained, even if going forward the worst inflow sequence on record was repeated. The Commission regularly updates and publishes the Minzone analysis.

If hydro storage drops below the Minzone, the Whirinaki plant is dispatched into the market and continues to generate until storage rises back above the Minzone. The Commission is also able to use Whirinaki to address security of supply problems that are not related to dry year risk. A price trigger is used as a proxy for such problems—if the spot price of electricity rises above 20 c/kWh, Whirinaki is dispatched regardless of whether the Minzone has been breached.

The Commission also uses the Minzone to assess the need for additional reserve energy going forward. Once a year, the Commission forecasts the Minzone for the next two years. It then examines the highest point of the curve, expressed as a percentage of total storage in the system. This point represents the highest minimum level of storage that will be required over the next two years to ensure security of supply standard is met.

If this point is too high, maintaining storage at this level will be costly because of a high risk of hydro-spill. Accordingly, the Commission calculates an ‘optimal’ Minzone peak by finding the point at which the costs of procuring additional reserve energy would be equal to the expected costs of hydro spill. Originally this point was indicatively set at 70 percent of total storage, but is now calculated separately for each assessment. If the Commission finds that the forecast Minzone peak exceeds the ‘optimal’ one, the Commission will seek to procure additional reserve energy to move the projected peak down to ‘optimal’ level. However, to date, no need for additional reserve energy had been identified.

Lastly, in order to minimise market distortions the Commission:

- Provides extensive information to the market
- Has clearly specified and made public the offer strategy for Whirinaki, and has abided by that strategy, and

- Has committed itself to delaying any additional reserve energy procurement for as long as possible.

### 2.1.3 Managing a worse than 1-in-60 dry year

Should a worse than 1-in-60 dry year occur, more direct intervention may be required by the Commission to help ensure security of supply is maintained. The Regime stipulates that in such circumstances the Government expects the Commission to:

- Activate a conservation campaign in a timely manner
- Ensure contingency arrangements are put in place for the use of ripple control, and
- Put in place contingency arrangements to provide for the scheduling of rolling outages, in the extreme event that blackouts are required to ensure a balance between supply and demand.

## 2.2 Legal Basis for the Current Arrangements

The regulatory framework for reserve energy in New Zealand is provided by three main documents:

- The Act
- The GPS issued by the MED, and
- The Policy issued by the Commission.

Other Commission and MED documents, such as the draft New Zealand Energy Strategy, the Commission's annual Reserve Energy Needs Assessments, the Whirinaki Offer Strategy, and the draft Emergency Response Plan are also relevant, and have been considered as part of our analysis.

Sections 172O(1)(d) and (j) of the Act define the Commission's functions with respect to security of supply, namely to:

*“use reasonable endeavours to ensure security of supply (including contracting for reserve energy), without assuming any reduction in demand from emergency conservation campaigns, while minimising distortions to the normal operation of the market...”*

and to

*“give effect to GPS objectives and outcomes...”*

The GPS then provides further guidance to the Commission on security of supply objectives and how those objectives are to be achieved. The Regime is set out in paragraphs 35 to 67 of the GPS.<sup>7</sup>

The Regime requires the Commission to develop and implement a Policy that sets out how the Commission plans to achieve the security of supply objectives of the Act and meet the requirements of the Regime. The Commission's initial Policy was published in June 2005.<sup>8</sup> However the Commission has, in effect, operated in accordance with this Policy since the middle of 2004.

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<sup>7</sup> [http://www.med.govt.nz/templates/MultipageDocumentPage\\_23103.aspx#A4](http://www.med.govt.nz/templates/MultipageDocumentPage_23103.aspx#A4), October 2006

<sup>8</sup> <http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/Initial-SOS-Policy.pdf>, June 2005

### 2.2.1 Relative scope of Act, GPS and Policy

As noted above, the Act provides only high-level guidance to the Commission. However, the Act does make it clear that:

- Reasonable endeavours (as opposed to some higher standard, such as ‘best endeavours’) should be used to ensure security of supply. Hence, the Act recognises that, while security of supply is important, it should not be achieved at all costs
- Reasonable endeavours include contracting for reserve energy. This recognises that other approaches can be used to ensure security of supply
- Security of supply should be ensured without the need to resort to emergency energy conservation campaigns, and
- Distortions to the normal operation of the market should be minimised.

While the Act provides a fair amount of flexibility, the Regime gives detailed instructions on how the Government expects the Commission to meet the requirements of Section 172O(1)(d). For example, it states that:

- A Minzone should be calculated and that it must:
  - Be calculated at a national, rather than catchment-specific level
  - Take into account likely transmission constraints, and
  - Take into account the expected availability and use of thermal plant
- An Emergency Zone should also be calculated that would trigger a conservation campaign if there is a significant probability that a worse than 1-in-60 dry year event is occurring
- Plant contracted under the reserve energy Arrangements should primarily have low fixed costs and high operating costs, including plant that would otherwise have been mothballed or retired, rather than baseload plant
- That reserve energy should be offered into the market:
  - Either at the greater of 20 c/kWh and the variable payments that have been contracted for, or
  - If the Minzone is breached, at any lower price that allows the reserve energy to be dispatched and thus preserves hydro storage.

As a result, despite being responsible for implementing the Regime, the Commission can apply relatively little discretion when designing the Policy.

The Policy does however provide further detail on the Commission’s approach to:

- Calculating the Minzone
- Assessing the need for reserve energy to be procured
- Dispatching any reserve energy procured
- Establishing an Emergency Zone
- Carrying out short-term (two, four and six months), two year and ten year Energy Security Assessments, and
- Managing conflicts of interest.

### 3 Defining Security of Supply

What do we mean by ‘security of supply’? In simple terms, it means no power cuts. But should we really aim to have no power cuts at all? That is, should security of supply be absolute, or do we need to define the level of security we need (and conversely, the risk of power cuts we will accept). Why does our electricity market not, with its sophisticated wholesale power pricing, ensure the ‘right’ level of security automatically?

In this section we:

- Define security of supply, pointing out that absolute security of supply is not attainable or economic. We therefore recommend a definition of ‘relative’ security of supply as *“having enough supply to meet demand over a specified period, with a specified level of probability”*
- Describe the three categories of things that cause an **insecurity** of supply, namely: lack of generating capacity; lack of energy; and lack of transmission or distribution capacity. Transmission and distribution adequacy is outside the scope of this report, so we do not deal further with that issue. In most overseas jurisdictions, lack of capacity is the major concern. Capacity adequacy may become a concern in New Zealand, but currently, lack of energy is still the major risk, and the focus of this report, and
- Discuss various possible **measures** of security of supply, namely; the volume of un-served energy; the probability of demand restraint being needed, and the reserve energy margin. We argue that for calculating an optimal level of security of supply the most appropriate definition is *“the proportion of total demand that cannot be served”*. However, for setting a workable standard (discussed in Section 5), the best policy measure is likely to be the reserve energy margin.

Section 4 builds on these concepts to estimate an optimal level of security of supply, after which Section 5 describes how the desired security of supply level can be operationalised as a standard.

#### 3.1 Definition

As a matter of common sense, one thinks of absolute security of supply as **always having enough power supply to meet demand**. In the electricity system, supply is fixed at the amount the available generators can produce. But customers can take as much power as they like, just by turning on more electricity-consuming equipment. This creates the possibility that customers might try to use more power than can be produced. If this happens, the system operator will respond with staged power cuts.<sup>9</sup>

The risk of demand exceeding supply, and hence of power cuts, comes about because of important differences between the electricity market and other more normal markets. In particular:

- Customers cannot generally be physically prevented from taking as much power as they want, and
- Many customers do not respond to rising wholesale prices by cutting back demand, because they do not face the rising prices. (see Box 3.1)

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<sup>9</sup> The alternative is that the excess consumption could so strain the system that the entire grid could cut out. It is to prevent this that the system operator will institute smaller power cuts.

This risk of power cuts creates the need for some mechanism to promote security of supply. At the same time, the cost of achieving absolute security of supply may be too high. Accordingly, it may be more realistic to use a relative security of supply concept.

We define relative security of supply as:

*...having enough supply to meet demand over a specified period with a specified level of probability.*

### **Box 3.1: Security of Supply and Prices**

In many goods markets, supply is always enough to meet demand because prices moderate both. If supply is reduced, prices rise to attract supply from more costly sources and to suppress demand to be within the level of supply available. If supply is inflexible or if demand is inflexible, prices would simply need to go as high as necessary to keep the two in balance. Those who value supply most will be satisfied. Those who value supply less—perhaps because they have alternatives—will opt out.

Of course, these mechanisms are in operation in electricity markets. When supply is tight, spot prices increase, higher cost sources like Huntly and New Plymouth are used more and major users reduce consumption to some degree.

However, the market may not always ‘clear’. The reason is that it is probably cheaper overall to allow for the possibility of some shortages than to arrange for all consumers to be exposed to spot prices and to have the necessary spot contracts and appliance controls. Retailers who act for small consumers cannot ultimately control load.<sup>10</sup>

Even where the market may clear, it is apparent that some major users are not comfortable with the prospect of essentially unlimited spot prices. Later in Section 5.3 we discuss the possibility of incorporating some limiting of consumer exposure to high spot prices—what we term ‘price protection’—into the Regime.

Source: Castalia

## **3.2 Causes of Supply Insecurity**

Insecurity of supply means a failure to achieve desired levels of supply security. It is the natural tendency toward **insecurity** that a security of supply policy is intended to combat, so we need to start by understanding what causes supply insecurity. At a high level, supply insecurity could be caused by three factors:

- Insufficient generating capacity (MW) being available to meet peak demand (capacity adequacy)
- Insufficient electrical energy (MWh) being available to meet demand over some period of time (energy adequacy), and
- Inadequate transmission and distribution capacity to deliver energy from where it generated to where it is consumed (network adequacy).

During the Review process, some parties submitted that these three factors should be considered holistically as part of the Review and that analysing these issues separately may lead to suboptimal outcomes. We agree that holistic consideration of all three factors is important when making decisions on action that impact the **actual level** of security of supply—such as deciding on where and when to build a new transmission line

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<sup>10</sup> This is the primary ‘demand side flaw’ in electricity markets as identified by writers like Stoft. See for example, *Power System Economics* by Steven Stoft, IEEE 2002, page 15. “...The flaw is the ability of a load ‘to take power from the grid without a prior contract with a generator’ (Ruff 1999; FERC, 2001)”

or reserve generator. These decisions affect the current and future level of security of supply with respect to all three factors. However, in our view, it is appropriate to separately consider each factor when deciding what security standard should apply to that particular part of the puzzle. There will likely be three separate security of supply standards for capacity, energy and network adequacy. For example, the network adequacy standard is often expressed as an N-x standard, referring to the maximum number of lines that can be out of service, while still ensuring supply is maintained.

Network adequacy is outside the scope of this Review and is addressed in the Commission's other work-streams. Therefore, this report focuses on the issues of ensuring energy and capacity adequacy to satisfy demand.

**Box 3.2: Clarifying Terminology: Energy, Capacity, Peak supply**

The Californian Energy Commission defines 'peaking capacity' as the capacity of generating equipment intended for operation during the hours of highest daily, weekly or seasonal loads.

Accordingly, we will use the terms 'peak adequacy' and 'capacity adequacy' interchangeably to refer to having enough MW to meet demand on an hourly timescale.

We will use the term 'energy adequacy' to refer to having enough generating plant (and the fuel to run it) to meet demand (MWh) over a period of months or years.

Occasionally we will use the term 'resource adequacy' to refer to both.

Source: Castalia

Energy and capacity are two separate, albeit closely related things. While any new generator added to the system will provide both additional energy and capacity, the relative contribution to these two aspects of the system will differ, depending on the type of generator. For example:

- A wind farm will provide a substantial amount of energy over a year, yet the capacity reliably added to the system at any particular point in time may be modest
- A hydro plant with limited storage may add substantial capacity to the system, but may not be able to reliably provide energy over a sustained period, and
- A diesel-fired open cycle gas turbine can add capacity cheaply, but will be a relatively expensive source of energy.

Outages due to inadequate capacity are likely to be confined to peak demand hours, whereas outages due to energy shortages will be sustained and may occur at any time.

The difference between generating capacity and electrical energy means that two separate security of supply standards may be required, the first relating to peak adequacy and the second relating to energy adequacy. In this Review, we emphasise energy adequacy but note where a standard for peak adequacy may need to be developed. We describe both types of shortages in Figure 3.1 and the explanatory text below:

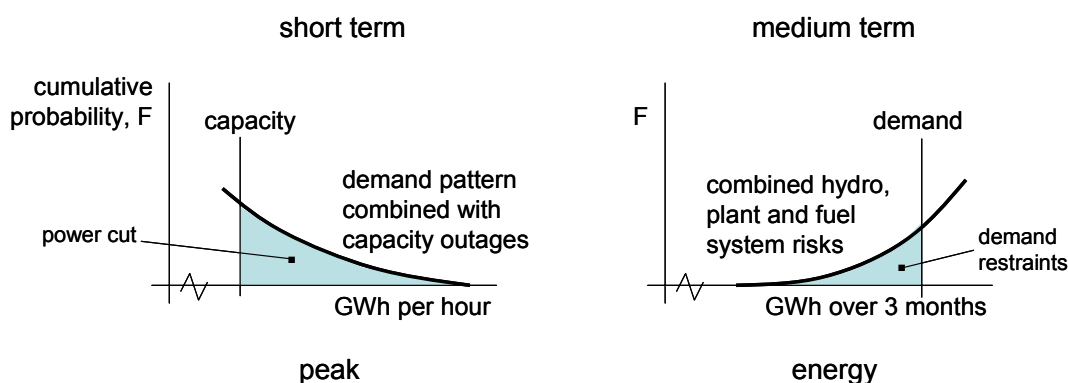
- **Peak adequacy:** In the short term (shown on the left in Figure 3.1) we are relatively certain of capacity but peak demand is uncertain. The uncertainty of peak demand<sup>11</sup> is depicted in Figure 3.1 as a probability distribution—the downward sloping curve shows the cumulative probability of each level of

<sup>11</sup> Peak demand is depicted in units of GWh per hour rather than GW or MW just as a reminder of the short time frame.

peak demand occurring. The curve is probably more familiar as the top of the load duration curve (the cumulative probability of demand),<sup>12</sup> stretched to account for unexpected outages. Once peak demand exceeds capacity, power cuts will occur. To calculate the total extent of power cuts occurring, we need to multiply each level of peak demand exceeding capacity by the probability of it occurring, and sum the result for all levels of peak demand. This is the equivalent to the shaded area under the curve in Figure 3.1.

- **Energy adequacy:** In the medium term (shown on the right), the roles are reversed—demand is relatively certain but energy supply is uncertain due to hydro inflows, wind, fuel supply risks etc. In this case, the upward sloping curve describes the cumulative probability of each level of supply occurring. The curve slopes upwards because, for a low level of supply to arise, more unexpected events have to occur. When supply is less than demand, demand restraints will be required. As described earlier, demand restraints will initially take the form of conservation campaigns but may ultimately require planned and forewarned power cuts. Once again, the shaded area under the curve is equivalent to the total extent of demand restraints required (in GWh over three months).

**Figure 3.1: Short and Long Term Security of Supply**



Source: Castalia

### 3.2.1 Medium term: energy adequacy

Energy adequacy can be threatened by low hydro inflows or other sustained losses of generation plant or fuel. We consider these in turn.

#### Dry periods

Earlier analysis by Morrison & Co shows that, in the medium term, the critical risk is a period of sustained low hydro inflows, creating an energy deficit relative to the expected supply of 2.5 to 3.5 TWh over three to six months.<sup>13</sup> This degree of vulnerability to an energy deficit is unique in the world in competitive electricity markets. (See Box 3.4.)

<sup>12</sup> The load duration curve is usually drawn with the MW axis vertical and the cumulative probability expressed in hours per year or percentages on the x-axis.

<sup>13</sup> Morrison & Co, 2004 *Issues Concerning the Reserve Energy Proposal*, Report to MED by John Culy, 22 January 2004

Hydro generators use the available storage to shift water stocks from the periods of higher inflows, lower demand and lower prices in Spring and Summer to the periods of lower inflows, higher demand and higher prices in Autumn and Winter. Our simplified description takes this hydro scheduling process as given and assumes that the deficit distributions capture the main supply effects.

In this preliminary analysis we also ignore the details of the inter-island imbalance in dry periods and the limited ability for the HVDC link to move energy south to compensate. We understand that our approach may need to be extended because dry year risk may now be somewhat more of a South Island problem rather than a New Zealand problem. This year, the binding Minzone is apparently the South Island Minzone. If the HVDC link is becoming a constraint, then North Island thermal generation will not be able to fully compensate for dry periods.

Retailers with insufficient contracts to cover their customers' demand will make substantial losses during dry periods when spot prices are high and they have to buy their shortfall. As a result, we expect market participants—acting in their own commercial interests—to provide enough generation capability—enough of an **energy margin**—to ensure that demand restraints (See Box 3.3) are unlikely. Of course, the central issue in security of supply policy is whether the market makes demand restraints 'unlikely enough'.

**Box 3.3: Definition of 'Demand Restraints' and 'Un-Served Energy' (USE)**

We use the terms 'demand restraint' and 'un-served energy' interchangeably. They include:

- Any voluntary demand reductions resulting from publicity about dry year problems
- Any voluntary demand reductions resulting from focussed conservation campaigns undertaken by government or power companies, and
- Energy saved by rationing.

By 'rationing' we mean power cuts that are planned to minimise the inconvenience to consumers.

It is helpful to distinguish these degrees of shortages. All are costly but the first voluntary reductions are clearly much less costly than any ultimate rationing.

In formulae, **USE** refers to the quantity of un-served energy as a **proportion** of total demand.

Source: Castalia

### Other energy risks

The description of Figure 3.1 above allows for a variety of medium term energy supply risks. However, the Regime is currently formulated in terms of a specific 1-in-60 dry year risk. The standard is hydro-focussed because hydro uncertainty has been regarded as the most significant risk to security of supply. In reality, the 1-in-60 dry year standard is equivalent to a combination of less unlikely hydro sequences with other possible disruptions. For example, a 1-in-60 dry year deficit may be the same as a 1-in-40 deficit combined with a substantial and sustained thermal plant outage.

Under the current Regime, the Commission can only procure Reserve Energy to deal with dry year risk, although, once procured, Reserve Energy can be used to deal with other threats to security of supply.

During consultation, many stakeholders suggested that the Regime should assess other threats to security of supply explicitly. These other threats included large transmission failures, extended periods of low wind (likely to become more important over time if

there is more wind generation as envisaged by the draft New Zealand Energy Strategy), disruptions on gas supply platforms, and major faults on gas transmission pipelines.

As noted above, issues related to the adequacy of transmission and distribution are being addressed in the Commission's other work-streams and are outside the scope of this Review. However, we agree that it would be useful for the Regime to consider security of supply at a more generic level than simply the threat of low hydro inflows.

In our view, the Regime should ask the Commission to consider all threats from rare, but foreseeable events (i.e. ones that a probability can be reasonably estimated for). It may well be that the hydro risk dominates all others, but it would be useful to determine this with more certainty, rather than simply assuming it is so.

Box 3.4 below summarises our review of approaches used to ensure security of supply in other countries that have similar electricity sector characteristics to New Zealand. More detail on approaches elsewhere is provided in Appendix A.

**Box 3.4: New Zealand's Unique Energy Security Problem**

Our review of international comparators shows that, of all developed countries with significant reliance on hydro generation, only Iceland can be compared to New Zealand in terms of geographical isolation. Most other hydro-reliant countries have significant interconnection with other countries in the region, thereby managing their exposure to dry years.

Furthermore, as demonstrated in the table below, in addition to interconnection, most hydro-reliant countries have significant reservoir storage (29 percent to 147 percent of annual consumption) to help manage dry year risk. New Zealand's hydro-storage, on the other hand, is only equivalent to approximately 10 percent of annual consumption.

Country	Hydro storage as % of annual consumption
New Zealand	10%
Brazil	85%
Iceland	29%
Norway	147%

The particular characteristics of the New Zealand electricity system therefore create a problem of security of energy (rather than peak capacity) that is unique.

Source: Castalia

### 3.2.2 Short term: peak adequacy

With a high proportion of hydro supply, New Zealand has long enjoyed plentiful MW capacity to meet peak demand, other than where transmission has been constrained from time to time.

As demand grows, new generation will be added. Most of this generation will be wind or thermal powered, not hydro. The proportion of hydro in the total generation mix will therefore decline. This means we can no longer take it for granted that New Zealand will have ample peaking capacity. On 19 June 2006, the country came very close to localised blackouts due to capacity shortages. Most observers believe that this was due to an unusual combination of constraints and plant outages, and raised questions about the

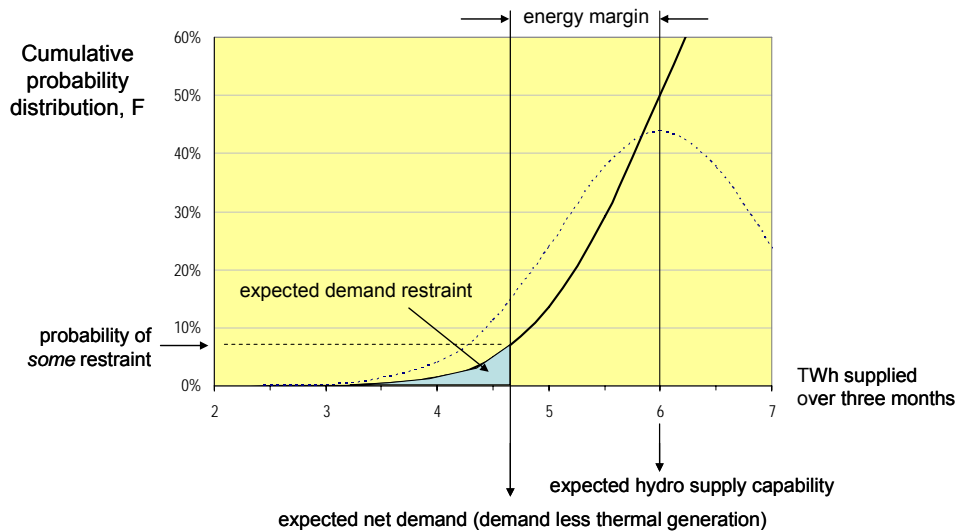
way the market handles plants with significant start-up costs rather than indicating that the New Zealand market is peak-constrained just yet.

When the time comes, the Regime will need to be expanded to provide a peak security of supply standard. The methodology for determining such a peak standard would be very similar to our recommended approach for calculating the energy standard, which is set out in Sections 5 and 6. An indicative calculation is also provided in Box 4.3.

### 3.3 Measuring Security of Supply

Figure 3.2 shows one natural framework for quantifying energy security of supply. We depict the supply capability of the system—for example, over a three month period—as a probability distribution (the dotted curve that we will refer to by the letter  $f$ ) of hydro supply.<sup>14</sup> The figure also shows the cumulative probability distribution,  $F$  for overall supply. Expected demand is also shown in the diagram. Because we are focusing on hydro-risk, we show expected net demand (demand less thermal supply), since this is the demand that would have to be met from hydro generation.

**Figure 3.2: Understanding Security of Supply Measures**



Source: from Morrison & Co, 2004, Figure 4.<sup>15</sup>

In Figure 3.2, the expected hydro energy delivery capability over the critical three month period of the year is 6 TWh.<sup>16</sup> In a normal year, 6 TWh can be supplied—more than enough to meet expected net demand (that is demand less available thermal generation), which in this illustration is around 4.7 TWh over the same three month period.<sup>17</sup>

<sup>14</sup> We assume for this analysis that hydro uncertainties are the dominant medium term risk. However, as discussed above, the distribution should ideally allow for other plant outages and fuel disruptions. The dotted curve is included as a reminder that the expected level of hydro supply over the three month period is 6 TWh. It is not drawn with reference to the left hand scale which is there for the (more useful) **cumulative** probability distribution.

<sup>15</sup> Morrison & Co, 2004 *Issues Concerning the Reserve Energy Proposal*, Report to MED by John Culy, 22 January 2004

<sup>16</sup> This is a quarter of average annual inflows.

<sup>17</sup> We focus here on dry years and therefore depict hydro supply and demand-less-thermal-generation rather than total supply and total demand. The energy margin is the same either way.

However, hydro inflows are variable. This variability is illustrated by the probability distributions. The probability that achievable supply will be less than net demand is around seven percent. In other words, in this example there is about a seven percent chance that demand will have to be ‘restrained’ somehow. The restraints would be achieved by warnings of shortages, conservation campaigns and, ultimately, through direct controls like pre-announced rolling power cuts in particular localities for specific groups of customers (see Box 3.3).

We can now see that Figure 3.2 provides three possible measures of security of supply:

- **The Expected Proportion of Un-served Energy.** The expected MWh level of demand restraint at a particular time in the future is the sum of individual shortage possibilities multiplied by the individual probabilities and is given by the **shaded area** under the cumulative distribution. In this example, the expected level of un-served energy is 35 GWh, which is 0.35 percent of the three-month demand or 0.0875 percent of total annual demand
- **Probability of Demand Restraint.** This can be read off the vertical intercept. In this illustration, there is a 7.7 percent chance (1-in-13) of some demand restraint being needed
- **Energy Margin.** The energy margin is the difference between expected net demand and the expected hydro supply capability. The higher the energy margin (that is, the greater energy supply capability is than expected demand), the greater the level of security of supply.

Of these measures, the Probability of Demand Restraint is the one most similar to the current concept of a 1-in-60 year chance of conservation campaigns or rationing being required. However, in the following section we show that for the purpose of calculating the optimal level of security, it is actually the Expected Proportion of Un-served Energy that is the more relevant concept. For setting a workable standard, the Commission needs to address something that it can control. We argue in Section 5 that the relevant definition for standard setting should be the Energy Margin.

## 4 Calculating the Optimal Level of Security of Supply

In this section we estimate the economically optimal **level** of security of supply. We find that the optimal level of security of supply is likely to:

- Involve an expected level of un-served energy each year of around 0.05 percent (the plausible range being between 0.025 and 0.1 percent) of total **annual** demand, which
- Equates to a probability of demand restraint in the region of about 1-in-20 (the range from 1-in-11 to 1-in-35), and
- Implies an optimal energy margin in the range of about 15 percent (the range being from 12 percent to 17 percent).

All of our estimated plausible range for the optimal security of supply is lower than the current policy aims to achieve. As a simple comparison, a 1-in-30 chance of some demand restraint being needed would lead to some demand restraint being required about twice as often as under the current 1-in-60 dry year definition.<sup>18</sup> We stress that these are preliminary calculations designed to illustrate the methodology and inform the Commission's and the Government's thinking, rather than anything definitive. We discuss later how the precise energy margin should be calculated.

The rest of this section sets out an approach to calculating the optimal level of security of supply. The analysis involves the following steps:

- First, we describe the analytic approach to calculating an optimal level as the point at which the marginal cost of increased demand restraint equals the marginal cost of increased security of supply
- Second, we estimate the cost of demand restraints
- Third, we estimate the cost of increasing security of supply
- Fourth, we calculate the level of security of supply at which the marginal cost of demand restraint and the marginal cost of increased security are equal, and
- Finally, we reality-check these indicative results against the security of supply levels used previously in New Zealand, and approaches used overseas

### 4.1 Theory behind Calculating the Optimal Security of Supply

We know that absolute security of supply is not a sensible objective. Massive redundancy in plant and fuel supplies would be needed. But what level of security should we aim for?

From an economic point of view, the optimal level of security of supply is that which minimises the total combined cost of un-served energy and security of supply mechanisms. Remember that un-served energy includes both conservation campaigns and any rationing and that rationing is managed to minimise disruption to high priority loads.

The risk and extent of outages can be reduced, at a cost, by adding generation to the system, or paying customers to reduce demand—both of which create additional energy

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<sup>18</sup> About twice, but not exactly, since the 1-in-30 definition refers to demand restraint from all events, while the 1-in-60 standard targets only demand restraint as a result of dry years.

and capacity in the system. At the margin, one would incur the cost of improving security of supply until the cost of improving it further is equal to the cost of the expected outages. Going beyond this point would mean that the cost of avoiding the outages is higher than the avoided cost of the outages occurring.

Accordingly, the optimal level of security of supply standard can be identified as the point where the marginal cost of demand restraints is equal to the marginal cost of additional reserve energy. The following sections estimate the cost of demand restraint, and the cost of adding reserve energy.

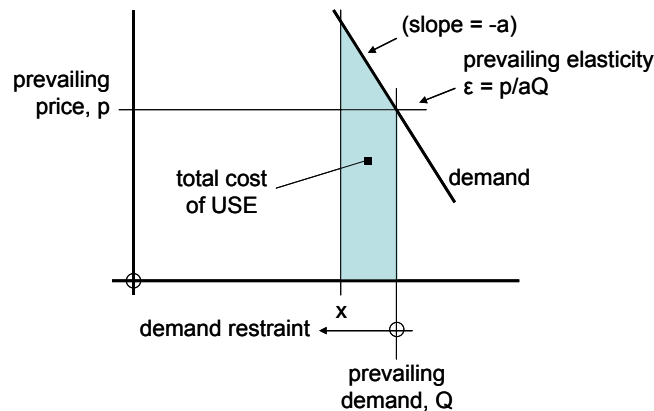
## 4.2 Cost of Demand Restraints

In this section we set out a way of estimating the cost of a particular level of demand restraint and then show how one can estimate the **expected** cost of shortages.

The cost of conservation campaigns or rationing programs obviously depends on how much consumers value power supply. The value to consumers of differing levels of supply is usually represented by the electricity demand curve. In fact, the demand curve records the marginal value of supply to a **representative** customer at different levels of supply.<sup>19</sup> For example, in Figure 4.1 at a level of demand  $Q$ , the value of an additional unit of supply to customers is  $p$ . Stated differently, if the market price is  $p$ , demand will be  $Q$ .

Figure 4.1 shows a plausible demand curve. It assumes that demand varies linearly with price in the vicinity of the prevailing price and prevailing demand. In the undisturbed market, the retail price is  $p$ , say 18 c/kWh, and the demand is  $Q$ . If consumers are encouraged or forced to take less electricity—as shown by the movement  $x$  in supply back from  $Q$ —they lose the value they would have derived from that consumption.

**Figure 4.1: The Cost of Un-served Energy with Linear Demand**



Source: Castalia

Note that we are concentrating here on dry year demand restraints that are voluntary or arranged with considerable advance warning and focused on loads that will suffer the least inconvenience from the cuts. Power cuts at peak times or resulting from transmission outages would be much more costly. The analysis could be undertaken using a similar diagram but the demand line would be much steeper, signifying much more rapidly rising costs with respect to the amount of power cuts.

<sup>19</sup> This is clearly a simplification of the range of values to different consumers of power supply.

The total cost of a particular level of demand restraint is the shaded area under the demand curve. The area measures the gross value that consumers would have achieved from the electricity use that has been suppressed. The cost increases relatively quickly as the demand restraint,  $x$  increases. From the position and slope of the demand line, the cost can be written as:

$$C(x) = px + \frac{1}{2}ax^2$$

The first term corresponds to the rectangular part of the shaded area loss below  $p$  and to the left of  $Q$ . The second term records how the triangular part of the shaded area loss grows as the demand restraint  $x$  increases.

The **marginal** cost of demand restraints, that is, the additional cost per **additional** MWh of demand restraint is just the demand curve viewed from the prevailing price and quantity:

$$C'(x) = p + a.x$$

This is much as one would expect. The first term records that each unit of energy withheld must be worth at least the prevailing price to consumers or they would not have purchased the original amount. The second term captures the idea that successive amounts of demand restraint are progressively more annoying and costly to consumers.

Finally, we write the marginal cost of un-served energy as

$$p + aQ.USE$$

where  $USE$  in the formula is the **proportion** of ‘un-served energy’,  $x/Q$ .

The term  $aQ$  can also be written as  $p/\varepsilon$  where  $\varepsilon$  is the prevailing short run elasticity of demand at current prices.

### Calibration

Now we need to put real numbers into the above illustration. We know prevailing retail electricity prices are around 18 c/kWh. What we need to estimate is how steeply the cost of conservation campaigns and rationing is likely to rise with deeper cuts. We have shown how demand restraints should be regarded as progressively more costly, the deeper they are. Now, we need to quantify this effect to be able to trade the costs off against those of reducing the restraints.

Morrison & Co surveyed a range of values of lost load (VoLL) with varying degrees of depth and forewarning.<sup>20</sup> Where there is substantial warning and rationing can be targeted, Morrison & Co suggest that the marginal cost of **some degree of rationing** should not exceed **\$5/kWh**.

The first few percent of savings may be achievable by warnings of shortages; further cut-backs may be achieved with a full conservation campaign; and any deeper shortages will be dealt with by carefully planned rationing. The **conservation campaigns** in recent dry years appeared to achieve approximately a **10 percent** reduction in demand over the critical period.

Given these reference points, we believe the best anchor for quantifying the cost of demand restraints is to assume that energy savings of **10 percent** can be achieved in the critical winter period before the marginal cost of USE reaches close to **\$2/kWh** above the prevailing retail price. Rationing of an additional 10 percent (beyond the voluntary

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<sup>20</sup> *op.cit.*

10 percent) would take the marginal cost to \$4/kWh above the prevailing price, and so on.

Referring to the equation above for the marginal cost of USE, this benchmark of demand restraints costing \$2/kWh at 10 percent USE implies that the combined coefficients  $aQ$  must equal 2,000 c/kWh or \$20/kWh (\$2.00/10%).

Expressed another way, the marginal cost of demand restraints rises from the prevailing price  $p$ , say 18 c/kWh, at a rate of 20 c/kWh for every percentage point of restraint.

This benchmark corresponds to a demand elasticity of 0.009 ( $p/aQ = 18/2000$ ). This elasticity captures the inconvenience to customers caused by demand restraints. One would expect it to be lower than the elasticity for changes in prices over a yearly timeframe and of course, substantially less than the long run elasticity that allows for changes in electricity-using equipment.

Short run demand elasticities—over a year say—for electricity might commonly be taken to be around 0.1. This would correspond to an  $aQ$  value of 180 c/kWh and a marginal cost of demand restraints of only 36 c/kWh at the 10 percent limit of conservation campaigns.

Clearly, this benchmark will be important in identifying the optimal level of security of supply, but is hard to define more precisely, given the range of circumstances of consumers, the unpredictable nature of voluntary savings and of the precision of rationing in targeting ‘low priority’ demand. From the experience of previous shortages and the existing analysis of this type of medium-term VoLL, the most one can say is that the marginal cost at the 10 percent likely limit of voluntary savings is very likely less than \$5/kWh.

**Box 4.1: Stakeholder views on marginal costs of demand restraints**

During consultation most stakeholders agreed that it is difficult to accurately estimate the marginal costs of demand restraints, but that Castalia’s estimates are a reasonable starting point.

Some stakeholders also suggested that the cost estimates should include the impact of a particular security standard on the level of business confidence from investors. For example, an investor that considers the security of supply standard to be too low will be less willing to invest in the New Zealand economy. This issue is discussed in Section 5.2

While that logic is valid (all consumers would prefer a higher level of security of supply if that level comes at no direct additional cost to them), it is not clear how one would estimate investors’ attitudes with respect to any particular standard and the relationship between those attitudes and dollar impacts on actual investment.

Source: Castalia

**The expected cost of demand restraints**

Given the costs of particular levels of demand restraint derived above and the probability distribution  $f$  of differing levels of supply, we can calculate the expected cost of demand restraints as:

$$\int_0^Q f(q)C(Q - q)dq = \int_0^Q F(q)C'(Q - q)dq$$

In these expressions,  $q$  is the available supply level and  $Q$  is the level of total demand so  $Q - q$  is the MWh shortage level that was written as  $x$  in the expression for  $C$  earlier.

The first expression represents adding up the different shortage possibilities with the probability of each. The second expression notes that the cost can also be expressed in terms of the **cumulative probability** distribution,  $F$ , of hydro supply (that we discussed earlier) and the **marginal cost** of the demand restraints.

### Quantifying the marginal cost of expected USE

Recall that we are in the process of deriving the optimal balance of costs of supply and of non-supply by equating marginal costs. The next step is to identify the marginal cost of expected demand restraints, that is, how much the expected cost of demand restraints is increased if the level of demand is increased (or equivalently, if the level of reliable thermal supply is reduced).

From the expression above one can show that the expected marginal cost of un-served energy is:

$$FC'(Q) + \int_0^Q F(q)C'' dq$$

$$= pF + aQ.USE$$

To recall,

$p$  is the prevailing representative retail price, say 18 c/kWh

$F$  is the probability of at least some demand restraint and  $USE$  is the expected proportional amount of demand suppressed by conservation campaigns and rationing

$Q$  is the prevailing demand, and

$aQ$  we calibrated provisionally as 2,000 c/kWh.

Accordingly, we can write the **expected marginal cost of demand restraints** as:

$$18 F + 2,000 USE \text{ in c/kWh}$$

As an example, consider the values shown in Figure 3.2 for that particular level of hydro supply and net demand. There, the probability of some demand restraint was  $F = 7.7$  percent and the expected level of un-served energy  $USE$  was 0.35 percent over the critical three-month period. Using the formula, the expected marginal cost of the un-served energy would be 8.4 c/kWh. This is the probability-weighted loss arising from the last kWh of demand. The expected cost of the last unit not supplied is given by dividing through by  $F$  to give \$1.09/kWh. If the net demand line were further to the right, implying a higher level of demand restraint, both  $F$  and  $USE$  would be higher. As a result, the expected marginal cost of the restraints would be higher, as we would expect; deeper cuts cost progressively more per kWh.

Note that this range of costs of un-served energy is different from, and lower than, the more familiar VoLL (see Box 4.2) applied in thermal systems or to transmission outages. The reason for this is that in these settings, VoLL estimates the cost of unexpected and indiscriminate power cuts at peak times. It follows that VoLL is higher than the cost of un-served energy in conservation campaigns and planned and well-publicised power rota-cuts.

#### **Box 4.2: Cost of Shortages at Peak Time**

When demand increases unexpectedly or there are major plant outages in the short run, the system operator may have to shed load in a relatively indiscriminate way. In this setting, it is more common to adopt a single representative measure of the cost of shortages, the VoLL. Typical values might be \$20/kWh to \$40/kWh, much higher than the likely range for conservation campaigns or rationing in energy shortages.<sup>21</sup>

With this single **unit** cost, the total cost of USE is just  $VoLL \times USE$  and the marginal cost of USE at peak is  $VoLL \times F$ , where  $F$  is the likelihood of non-supply at the given level of expected system MW capacity (as in the left hand part of Figure 3.1). Box 4.3 provides an indicative calculation of the optimal level of peak security.

VoLL would be a relevant concept for setting a security of supply mechanism for capacity-related shortages. It is not a relevant concept when dealing with energy related shortages, since energy related shortages can be addressed through conservation campaigns and planned rota-cuts, which impose lower costs per kWh saved.

Source: Castalia

### **4.3 The Marginal Cost of Increasing Security of Supply**

The penultimate step in finding the optimal level of security of supply is to find the marginal cost of increasing security of supply.

#### **Assumptions**

There will be a range of ways to augment medium term security of supply. As with demand restraints, there will be a rising marginal cost. For this calculation, we assume that, at the relevant balancing point, the cheaper options (such as contracted demand response) are taken up and reserve generation is required.

This assumption requires further testing when the security of supply standard is set. For example, it may be that sufficient contracted demand response will be available in future to reach the balancing point—some submitters noted this during consultation. Castalia agrees that contracted demand response would likely be the cheapest method to increase security of supply. However, there is currently insufficient information on:

- The realistic extent of savings that can be achieved using contracted demand response
- The cost of such response, and
- The practical issues around contracting for demand response in addition to the response that would occur in any case if spot prices increase.

Demand response participation in the electricity market is being addressed by the Commission in a separate work stream. As that work stream progresses, the security standard will need to be updated to take into account any new robust information regarding the potential to use contracted demand response instead of additional generation, and the resulting impact on the marginal cost curve for increasing security of supply.

#### **Calculation**

At the relevant balancing point, the lowest capital cost generation option are diesel-fired open cycle gas turbines with a fuel cost of approximately 20 c/kWh and a capital cost of

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<sup>21</sup> One could use the same approach as outlined above if one had estimates of the rising marginal costs of short term power cuts.

about \$85/kW/year. If the plant were generating to capacity all year, the capital component would amount to 1 c/kWh.<sup>22</sup> By comparison, a baseload conventional coal-fired plant would cost 4 c/kWh for fuel and 4 c/kWh for capital. Clearly, diesel-fired open cycle gas turbines are an expensive way to generate power. Their attraction is their low capital cost. Minimising the capital tied up for occasional dry years is an important part of a least-cost reserve energy policy.

If the reserve energy plant is shoring up energy supply for just some fraction of the year  $\alpha$  (a quarter with our assumption that the critical hydro deficit typically lasts three months), then the expected marginal cost of reserve energy supply in that shortage period is the expected fuel cost and the capital cost recovered over just that period:

$$20 F + 1/\alpha \text{ in c/kWh}$$

Here:

$F$  is the expected level of utilisation of the additional reserve energy supply capacity in the critical period

$\alpha$ , as above, is the proportion of the year over which the critical hydro shortage materialises

From Figure 3.2, we can see that additional reserve energy will move the **net** demand line to the left. This means that the probability of utilisation of the marginal reserve supply capability is the same  $F$  as in the figure.  $F$  is equal to the probability of **some** demand restraint. If the representative hydro and other fuel shortage is a three month affair ( $\alpha = 1/4$ ), then the expected marginal cost of additional reserve energy from diesel-fired open cycle gas turbines is:

$$20 F + 4 \text{ in c/kWh}$$

This is the marginal cost of reserve energy with respect to the level of reserve energy capability. The marginal cost with respect to the energy actually supplied is given by dividing by  $F$  and so is equal to  $20 + 4/F$  in c/kWh. So, using the same sample parameters from Figure 3.2 as in Section 4.2 above, when  $F = 7.7$  percent, the marginal cost of the last unit supplied is  $20 + 4/0.077 = 72\text{c/kWh}$ . This cost is less than the \$1.09/kWh value of the last unit not supplied, implying that the optimal level of  $F$  will be lower than 7.7 percent.

#### 4.4 Estimating the Optimal Energy Security of Supply

We now take the final step in deriving the optimal level of security of supply.

##### Equating marginal costs give an optimal level of USE

As described above, the optimal level of security of supply minimises the expected total cost of supply and demand restraints. At the minimum total cost, the expected **marginal** cost of demand restraints will equal the expected **marginal** cost of increasing energy security of supply.

Combining the two equations, we set:

$$18 F + 2,000 USE = 20 F + 4 \text{ in c/kWh}$$

We solve this optimal condition by reference to Figure 3.2, finding the  $F$  and  $USE$  values that satisfy the equation. As it turns out, because the fuel cost of diesel-fired open cycle

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<sup>22</sup> If the kW generated for 8,300 hours in a year, generating 8.3 MWh, the \$85/kW/year annuity cost of the investment converts to about \$10/MWh or 1 c/kWh.

gas turbines is numerically close to the prevailing average retail price, the  $F$  value makes no difference to the calculation and the equation gives an estimate of the optimal level of un-served energy as:

$$USE = 4/2000 = 0.2\%$$

In other words, the cost-minimising combination of demand restraint and reserve energy defines an optimal level of un-served energy of **0.2 percent in the critical three month period**. This can also be expressed as **0.05 percent of total annual demand**.

#### **Box 4.3: The Optimal Level of Security of Peak Supply**

As discussed in Box 4.2, the calculation is different when dealing with capacity-related or peak security of supply. The marginal cost of peak supply is  $18F + 1$  c/kWh and the marginal cost of USE at peak times is  $VoLL * F$ , say  $3,000 F$  in c/kWh.

As a result, the optimal condition for peak security of supply is

$$F = 1c/VoLL = 1/3,000 = 0.003, \text{ which is } \mathbf{3 \text{ hours of USE per year or } 0.008 \text{ percent}}$$

If all un-served energy has the same \$30/kWh unit cost, then the optimal condition specifies only the probability of non-supply. The expected extent of non-supply (GWh) is not relevant.

Source: Castalia

#### **The corresponding optimal energy margin**

The required level of security of supply is secured by adding to thermal supply, thus moving the net demand line to the left in Figure 3.2 to leave less of the supply 'tail' below the new expected net demand. In the diagram, an energy margin of **1.5 TWh** for three month period would reduce the expected three month level of USE to 0.2 percent. If this energy margin were secured by plant that could operate all year, then the annual margin being provided would be 6 TWh, an annual **energy margin of 15 percent**.

It is important to clarify that the crucial energy margin is the energy that can be supplied over the critical three month period. Thermal power stations and their fuel arrangements need to be rated for this critical period. For example, for its full capacity to count, Huntly would need the stockpile and fuel delivery arrangements to enable it to run at capacity for the critical winter period. However, the **annual** energy margin measure would not be presuming that Huntly had fuel arrangements to run at capacity all year.

#### **The corresponding optimal probability of some demand restraint**

From the distribution in Figure 3.2, the  $F$  value corresponding to the optimal level of USE is about 1-in-20.

#### **Summary of the central estimates**

In summary, the economically efficient level of dry year security of supply appears to be in the vicinity of an expected level of demand restraint of 20 GWh, that is, 0.2 percent of demand over the critical winter period (or 0.05 percent of annual demand). The likelihood of this level of restraints appears to be about 1-in-20 and the standard would require a 15 percent energy margin.

Of course, other assumptions as regards the critical duration of the hydro risk and the rate at which the marginal cost of demand restraints increases will produce different results, but this formulation gives an indicative level to inform the Commission's and the

Government's thinking. In Section 4.6 below, we outline how the energy margin should be calculated in detail.

Hydro inflow distributions are uncertain but the three- and six-month hydro **deficit** distributions (like that shown in Figure 3.2) combine numerous inflow sequences and may be statistically more robust. Nevertheless, our fit to the distributions is approximate so inferring the optimal energy margin and optimal probability from the optimal *USE* measure is also approximate.

### **Sensitivity testing**

The optimal level of security of supply clearly depends on assumptions regarding the cost to consumers of demand restraints and the cost of augmenting security of supply. Some alternative sets of assumptions give different results:

- If the critical hydro deficit develops over six months rather than three, the capital cost of reserve energy will be halved but the optimal level of USE over the year remains at 0.05 percent. With the slightly different six month distribution of hydro deficits found by Morrison & Co, the probability of demand restraints is slightly different at **1-in-30** and the annual energy margin is slightly lower at **13 percent**
- If at the 10 percent limit of conservation campaigns, the marginal cost of un-served energy has only risen to \$1/kWh, rather than \$2 as assumed above (an elasticity of 0.018), then the optimal annual level of USE doubles to 0.1 percent. With this much lower assumed cost of shortages, the acceptable probability of some demand restraint is much higher at **1-in-11** and the required annual energy margin only **12 percent**, and
- If at the 10 percent limit of conservation campaigns, the marginal cost of un-served energy is already \$4/kWh (an elasticity of 0.0045), then the optimal annual level of USE halves to 0.025 percent. The optimal probability of some demand restraint is much lower at **1-in-35** and the required annual energy margin is **17 percent**.

### **Summary of the plausible range**

The optimal range of expected annual USE appears to be in the range of **0.025 percent** to **0.1 percent**. The corresponding range of probabilities of demand restraint is from **1-in-11** to **1-in-35** and the implied annual energy margin is between **12 percent** and **17 percent**.

## **4.5 Comparison with Previous and International Security of Supply Standards**

In this section, we briefly compare the range of plausible efficient standards for energy security of supply with the existing standard and with the traditional standard in New Zealand when the sector was centrally planned. Unfortunately, we have been unable to find a comparable **energy** security of supply standard in any overseas jurisdiction. A summary of international approaches to ensuring security of supply is provided in the box below. Further detail on international approaches is set out in Appendix A.

**Box 4.4: International approaches to ensuring security of supply**

Our international review shows wide variation of approaches adopted by different countries to ensure security of supply. The United Kingdom fully relies on the market to deliver, Iceland and Japan place obligations to supply on market participants, while Norway places that obligation on the system operator. Brazil seeks to centrally control generation investment, while Chile exposes customers to a significant risk of outages. The table below summarises the different approaches adopted by international comparators. In addition, the table summarises the approach used in the United States.

<b>Country</b>	<b>Approach to ensuring security of supply</b>
Iceland	All energy traded through contracts. Legislation requires suppliers to provide the electricity necessary to meet contract obligations. Demand growth driven largely by industrial investment, making it easier to underwrite new generation investment
Japan	Obligation to supply placed on vertically integrated utilities, in exchange for granting regional monopolies. The companies generally aim for a reserve margin of 8-10 percent
United Kingdom	Provide market with information and rely on market to deliver optimal security. Monitor whether a 1-in-50 cold winter peak demand can be met. A 20 percent reserve capacity margin is used as a monitoring benchmark by the system operator
Norway	A similar mechanism to New Zealand, with the system operator Statnett procuring reserve energy (or taking any other action as needed) to ensure security of supply. The reserve energy plant (gas turbines) can be dispatched when the probability of shortages reaches 50 percent in the relevant region and may be offered below SRMC. Statnett operates with a regulated revenue cap intended to absorb profits and losses from the operation of reserve energy plant.
Brazil	Government ensures security of supply by centrally planning and auctioning off any new generation projects. No clear framework for deciding when and how much new generation is required
Chile	Impose financial penalties on generators for any non-supply, but accept that some forced rationing may be required from time to time
United States	Loss of Load Expectation (LOLE) is set by the North American Electric Reliability Council, or a regional regulator. The LOLE is usually in the order of one day of non-supply in 10 years. Each region or market then decides how it will meet the LOLE requirement. Often, a minimum reserve margin is used—PJM aims for a minimum reserve margin of 15 percent, while Load Serving Entities in New York aim for 18 percent.

Overall, there are no clearly different approaches to inspire the analysis for New Zealand.

Source: Castalia

### Comparing with the existing 1-in-60 standard

From the approximate distribution depicted in Figure 3.2, 0.2 percent un-served energy (that is, 20 GWh in three months) corresponds to an  $F$  value—a likelihood level—of about 1-in-20.<sup>23</sup> This means expecting dry year demand restraints one year in 20 or a 1-in-20 chance of having dry year demand restraints in any particular year.

From the range of assumptions explored above, a plausible range for the optimal  $F$  value is 1-in-11 to 1-in-35. The whole range is substantially less demanding than the current 1-in-60 standard, suggesting that we are setting the bar too high for security of supply.

The 1-in-60 standard appears to correspond to a three month expected level of USE of about 0.055 percent (0.014 percent annual), less than the plausible range above. The corresponding annual energy margin would be around 19 percent.

For the 1-in-60 standard to be optimal, the costs of demand restraints would need to be higher than assumed above. At 10 percent demand restraint, roughly what can be achieved by conservation campaigns, the marginal cost would need to be \$7.30/kWh (an elasticity of 0.0025) substantially more than the marginal cost of some level of actual rationing as estimated by Morrison & Co.<sup>24</sup>

With the efficient standard likely to be less onerous than the current 1-in-60 measure, there is no reason to think that moving to a ‘worst of the past’ (now 1-in-74) standard would be more sensible.

### Comparing with the ECNZ dry year energy margin

The 12.5 percent to 18 percent provisional range for an optimal energy margin is broadly in line with the historical 7 percent ‘ECNZ dry year security margin’.

That standard required energy supply to be 7 percent above forecast demand, after assuming a 15 percent loss in hydro supply. At that time, average hydro supply was close to 70 percent of the total, so the convention provided a 17 percent energy margin.<sup>25</sup>

This is an interesting result because it counters the idea that central planners might have been excessively conservative.

#### **Box 4.5: Stakeholder feedback on Castalia’s estimates of an economic level of security of supply**

Of the stakeholders that commented on Castalia’s methodology for calculating the optimal range of expected annual USE, the corresponding probabilities of demand restraint, and the implied annual energy margin, all agreed that the methodology was reasonable. Some stakeholders suggested different assumptions that could be used.

Overall, however, most stakeholders, including all participating consumer representatives (MEUG, Grey Power and Ms. Melhuish), agreed that the current security of supply standard is too high and that Castalia’s analysis produces results that are closer to an optimal level.

Source: Castalia

<sup>23</sup> We fit the tail of the observed three month hydro supply distribution to a normal distribution with mean 6 TWh and standard deviation 0.91 TWh. The level of USE is 0.2 percent or 20 GWh if the net demand is 4.5 TWh over the three month period. At this point,  $F = 5$  percent.

<sup>24</sup> See page 34.

<sup>25</sup> 7% + 15% of 70%

## 4.6 Calculating the Precise Energy Margin

We have noted earlier that the calculations based on the hydro deficit distributions in Figure 3.2 need to be augmented to allow for other types of energy outages, demand uncertainty and operational constraints in the system, particularly North-South transmission constraints. The reason is that the optimal standard of security of supply depends on ensuring a particular level of un-served energy—the area in the tail of the supply distribution—so getting the necessary energy margin right depends on getting the shape of the tail right.

This section outlines a method for allowing for the additional risks and operational constraints, building on the Commission’s security of supply ‘needs assessment’. This approach will allow our provisional 15 percent estimate for the energy margin to be refined.

### Market simulation

The required energy margin can be found by directly seeking the minimum total cost of supply and non-supply that was discussed in Section 4.1. The margin that achieves the minimum total cost can be identified by **simulating** the operation of the system with different levels of diesel-fired gas turbines in place and recording the cost of different patterns of demand restraint according to the demand curve in Figure 4.1. The simulation should cover demand scenarios, a Monte Carlo treatment of major thermal plant outages, transmission constraints, and reservoir constraints and should use synthetic inflow distributions to allow for some sequences worse than those already experienced.

### Model several years out to minimise impact of starting storage

The probability of a shortfall of energy depends on both starting storage and expected inflows. As a simulation looks further forward, the effect of modeled inflows becomes more important and the effect of the assumed starting point storage level becomes less important. We suggest simulating three years out, starting with the current actual storage levels at the time the simulation starts.

### Model demand restraints as ‘deficit generators’

The aim of the modeling is to determine the expected cost of non-supply associated with a given level of reserve generation. The costs of non-supply should be modeled by including several ‘deficit generators’ that would be dispatched once all other available generation had been used. This would be achieved by pricing them above other generators.

The deficit generators’ notional ‘offer prices’ would reflect the assumed costs of non-supply to consumers as depicted in Figure 4.1 and calibrated in Section 4.2.<sup>26</sup> The cascade of deficit generators should thus mimic, as far as possible, the realistic process of initial demand reductions as prices rise, some voluntary reductions in demand arising from the conservation campaign, and higher costs from different degrees of forced rationing. We also think that consideration should be given to allowing for drawing lakes down below normal minimum levels in dry periods.

The total cost of non-supply for a given level of reserve generation capability would be the total cost of dispatching these ‘deficit generators’ over the period of simulation.

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<sup>26</sup> The modeling can use discrete non-supply deficit generators rather than a continuous supply curve like Figure 4.1

### **Simulate multiple inflow sequences**

From the given starting point, simulations should cover a range of three-year inflow sequences including, as mentioned above, some synthetic sequences worse than the historical set. It is likely that some subset of the total range of inflow sequences will account for all the relevant episodes of demand restraint. This should help economise on the modeling.

### **Reserve generation included**

Different sets of simulation runs (a set being all likely three-year inflow sequences from that point) should include different levels of reserve generation, more or less than is available at present to find the minimum total cost.

### **Generator offer prices**

We suggest that the simulations should assume that all plant, including the reserve generation plant, is offered at its SRMC. Hydro generator offer prices should be determined for each set of simulations based on water values from a hydro optimisation. This is equivalent to assuming that realistic market offers may make generators more or less money but will not seriously affect dispatch patterns, especially in dry periods.

### **Total cost of supply and non-supply**

For a given level of reserve generation, the total cost of non-supply for that set of simulation runs will be the sum over all inflow sequences of the product of the cost of non-supply for each inflow sequence and the probability of that inflow sequence occurring.

### **Repeat for different reserve generation levels**

In order to get the optimum trade off between the costs of reserve generation and the costs of non-supply, it will be necessary to repeat this exercise for several levels of reserve energy. Enough runs would need to be undertaken to determine the shape of the reserve energy versus non-supply cost curve. The minimum of this curve will determine the optimum reserve energy level or energy margin.

## 5 Setting an Operational Security of Supply Standard

This section considers the choice of practical **standards** for security of supply. Security of supply is both a political and a technical concept, and needs to be clearly understood by all stakeholders, including consumers, market participants, regulators, market commentators and political representatives. The algebra in the preceding section provides a technical framework for thinking about security of supply. In this section, we translate the algebra into a standard which can be widely understood and practically implemented. We also comment on two other considerations that may affect the choice of standards, investor confidence and price protection *per se*.

### 5.1 The Physical Standard for Security of Supply

Given optimal levels of security of supply for the short and medium term, how should one specify the standard?

The options include a 1-in- $X$  year probability of demand restraints (the  $F$  value defined earlier), an expected level of un-served energy (the USE defined above), a capacity margin for peak supply or a dry year energy margin.

We have shown in Section 4 that if diesel-fired open cycle gas turbines are likely to be the source of additional dry year energy, the optimal level of energy security of supply is specified most directly as an expected level of un-served energy.

To operationalise this standard, we suggest adopting a simple **percentage energy margin**. From modelled distributions of the hydro deficit like that shown in Figure 3.2, the Commission would infer the TWh per year energy margin required to confine the expected un-served energy to the chosen level.<sup>27</sup> This margin could then be combined with load forecasts as the Commission's declared position on security of supply. The implication would be that if the margin was eroded seriously in forecasts out to the lead time of new plant, the Commission would carefully consider procuring reserve energy.

If an energy adequacy hedge mechanism is implemented later, an energy margin plays no role. Instead all generation plant would be de-rated to define their dry year capacity.

#### **Box 5.1: Stakeholder feedback on use of simple annual percentage energy margin**

Most stakeholders agreed that an energy margin standard is appropriate. Genesis noted that a margin range would be more appropriate to reflect the uncertainty in estimating the correct margin. Transpower also commented that, rather than an annual margin, it may be more appropriate to use a margin for the likely period of shortage (three to six months). Orion noted that, to reflect transmission constraints, the margin may need to be calculated separately for different regions.

Meridian did not agree with the use of an energy margin, but did not suggest a specific alternative. Vector, on the other hand, suggested a standard presented as a percentage probability of supply being secure.

Source: Castalia

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<sup>27</sup> The process might require some adjustment for any hydro energy systematically lost due to transmission constraints.

## 5.2 Investor Confidence

In setting a security of supply standard, we need to acknowledge that the state of the nation's infrastructure and the standards to which it is maintained have an influence on the investment community. During consultation, some stakeholders also suggested that the marginal cost estimates of demand restraints should include the impact of a particular security standard on the level of investor confidence.

An attempt at quantifying this effect was made by Castalia on behalf of Transpower and presented to the Commission during its deliberations over Tranpower's proposal for the upgrade of supply into Auckland.<sup>28</sup> In that paper, Castalia attempted to put the costs incurred in improving security of supply in the context of welfare gains from increases in foreign direct investment (FDI). The difficulty, however, is in quantifying how, if at all, particular policy or regulatory decisions (such as approving a more obviously secure transmission upgrade or changing a security of supply standard) will affect the dollar flow of FDI. We understand that, in the case of the transmission upgrade, the Commission agreed with the principle that the perceived level of security of supply has an impact on FDI, but also concluded that there is no reliable way to quantify that impact.

The setting of the energy security of supply standard for New Zealand in principle involves the same pressures, even though—like us—international investors will have no obvious international benchmarks to compare the standard to.

## 5.3 Political Economy

Should the security of supply standard be raised to allow for the unpopularity of demand restraints? We think not.

What might appear in advance a prudent balancing of the costs of demand restraints and of reserve energy can easily be perceived as disastrously inadequate service levels and poor planning when a shortage actually occurs—especially with some creative media coverage. Power cuts are very unpopular and may lead to calls for the electricity sector to be restructured (again).

Rather than adding a margin of extra conservatism to the security of supply standard, we believe that this perception problem should be addressed head-on through the publicity material that advises the market and the media about security of supply. Security of supply monitoring publications and website notices should carry a reminder that absolute security of supply would be prohibitively expensive.

At the end of the day, the concepts involved are simple and can be understood by most customers, if properly and regularly communicated by the Government. The message is simple—New Zealand is in a unique situation with respect to energy supply:

- We are fortunate in having a large amount of clean, renewable hydro energy
- However, because hydro is largely dependent on rain, occasionally (once in 20 years), a shortage may occur
- We are an island nation and, as such, cannot import electricity to cover the shortage
- Therefore, we must either:
  - Occasionally (five percent chance in any given year) run conservation campaigns, or

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<sup>28</sup> Castalia 2006 *Foreign Direct Investment Effects*, August

- Build power plants that will spend most of their life sitting idle (around 95 percent of the time, if used only as dry year reserve), waiting for a shortage
- Given how expensive power plants are to build to remain largely idle, it makes more sense to have conservation campaigns from time to time.

#### **5.4 Pricing Considerations for a Security of Supply Standard?**

Up to this point, we have only addressed security of supply as a physical issue. High prices are generally correlated with periods of tight supply but spot prices can also be high without shortages. Throughout the policy discussions that surrounded the development of the existing Regime, concerns were expressed about high spot prices. Spot prices are necessarily volatile but price hedging was thought to be inadequate, possibly because of:

- Generators being too conservative in respect of their dry year exposure
- Generators not providing each other with adequate hedges for back up supply, and
- A lack of transparency in the hedge market, reducing large users' willingness to contract.

The performance of the wholesale market is under active review and we do not believe that compulsory hedging is required to protect all consumers. However, if providing some baseline protection for all consumers against high spot prices becomes an important government policy objective, the options in Section 6.2 would meet this need, as well as providing physical security of supply.

## 6 Achieving the Desired Standard

The previous sections of the report calculated an economically optimal level of security of supply, and considered how that level could be translated into a practical security of supply standard. In this section, we consider whether the market is likely to deliver the desired standard, and if not, what options are available for correcting the market.

Our analysis of forward generation investment commitments and plans indicates that we cannot rule out the possibility that the market will not deliver an appropriate level of security of supply—we refer to this as market failure, noting that this is different from the textbook definition of the term. On reasonable investment projections over the next ten years, the expected gross margin for the New Zealand electricity system may fall below the optimal level, save for the availability of energy from Whirinaki. While we can not dismiss the possibility that the existence of Whirinaki is itself crowding out some commercial investment, we find that with more conservative assumptions, the expected gross margin may be too low even with Whirinaki.

Markets may fail to deliver adequate resources to provide the socially optimal level of security of supply for a variety of reasons. Different causes of market failure would lead to a different frequency and magnitude of problems. The choice of the appropriate corrective mechanism will, in turn, depend on that frequency and magnitude. However, while it is useful to classify types of market failure in principle, we find that at present there is simply no information to identify in practice what may be causing potential problems, and how serious those problems are.

Hence, we need to develop a framework for deciding on an appropriate intervention policy under uncertainty. We consider the full range of interventions which have been proposed by various stakeholders. As a reference case, we examine the relative costs and benefits of adopting different interventions for each type of market failure, if the type of market failure were known.

We propose that without certain knowledge about the type—or even the existence—of market failure, corrective measures should aim to minimise the sum of errors: the error of intervening too much when less intervention is appropriate, and the error of not intervening enough when greater intervention is optimal. This logic translates into a ‘watch dog’ approach: the Commission should remain ready in case market failure becomes evident. The Commission should stand ready for a last minute procurement of further energy from contracted demand response or diesel-fired open cycle gas turbine capacity in the event it becomes obvious that, given lead times, sufficient market investment would not be in place before it becomes too late to commission such capacity. We refer to this as the last minute intervention.

If future market investments continue to keep the New Zealand system’s gross margin at the desired level, then no further security of supply investments would be needed, and no further interventions need to be considered until Whirinaki retires. If, on the other hand, the emerging market problem requires more last minute interventions, the Government will have an option of moving to a more comprehensive intervention.

### 6.1 Does the Market Fail?

The Arrangements exist because of a concern that the electricity market, as presently designed, may fail to provide resource adequacy. In this setting, market failure means that decentralised market decisions will not deliver adequate resources to provide the socially optimal level of security of supply.

### 6.1.1 Evidence of failures?

The MED tracks the gross security margin by comparing likely projects to expected load growth.<sup>29</sup> The MED concludes that there is sufficient investment in electricity generation, as the gross margin remains at least 20 percent through to 2012 (the last year of the analysis). The gross margin is the ratio of normal year energy production capability of the system, and the expected load.

This can be compared to the estimated plausible range for the optimal gross energy margin of 11 to 17 percent explained earlier, and the 19 percent implicit in the 1-in-60 standard.<sup>30</sup>

However, while the full list of prospective projects is fairly universally agreed, there is considerable uncertainty about the likelihood of each individual project proceeding at all, or proceeding within the expected time-frame. Below, we test the assumptions about individual investment projects for robustness, and consider the implications for security of supply.

Figure 6.1 follows the logic of the MED analysis, using planned project commissioning dates when known and projected commissioning dates based on appropriate lead times for each kind of generation when not known. However, we use more conservative probabilities for the likelihood of projects going ahead. In particular, given the direction indicated in the draft New Zealand Energy Strategy, we have allocated zero probabilities to coal projects, and very low probabilities to other thermal generation projects. Also, unlike MED, we only take into account generation investment that has been planned or well publicised. In contrast, MED has made assumptions about hypothetical generic investments in the future. Like MED, we assume capacity factors of 95 percent for thermal and geo-thermal plants, 52 percent for hydro, and 40 percent for wind.

Figure 6.2 uses the same probabilities of the project going ahead at all, but assumes that all commissioning dates are delayed by two years.

The low gross energy margins in Figure 6.2 reflect a very conservative scenario that combines the possible effects of the Government's climate change policy on thermal generation plans with possible delays to gaining consents, and other investment obstacles.

We consider gross margins with and without Whirinaki. Depending on the desired level of security of supply, one can develop three mutually inconsistent, but plausible, cases, namely that Whirinaki:

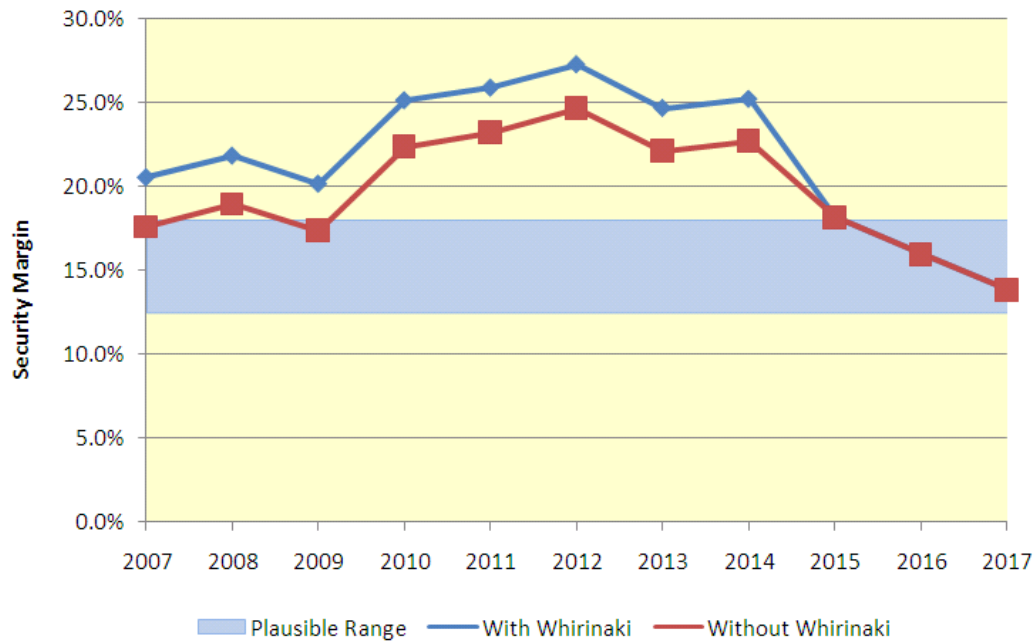
- Was not needed in the first place
- Was needed, but has now solved the security of supply problem for the foreseeable future, or
- Was needed, but is not enough to solve future security of supply problems.

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<sup>29</sup> 'Electricity Market Review: Summary of Review (Paper One)', Ministry of Economic Development, 2006

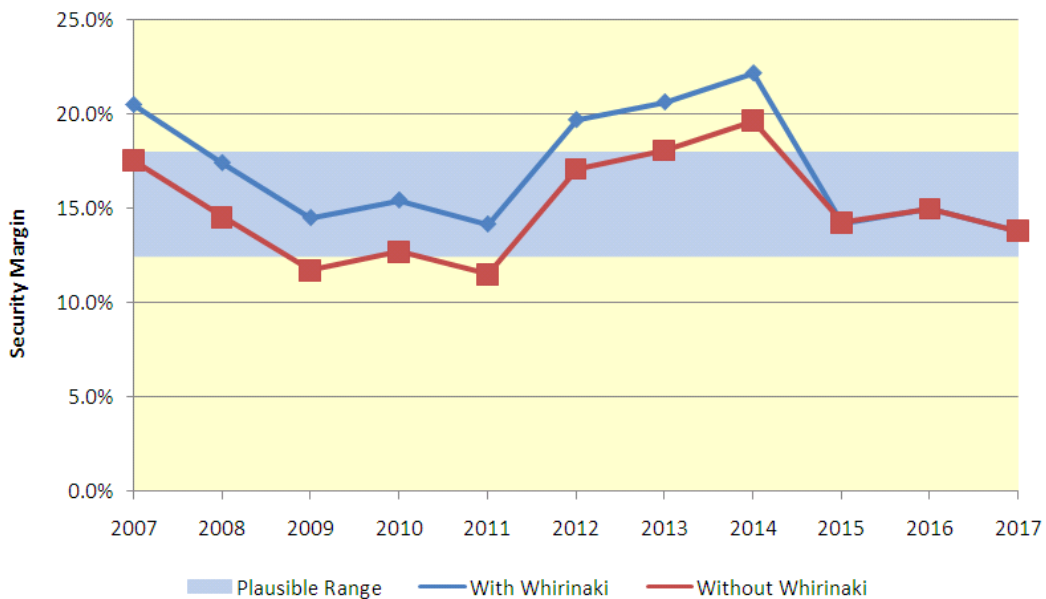
<sup>30</sup> see page 42

**Figure 6.1: Expected Gross Energy Margins**



Source: Castalia

**Figure 6.2: Gross Security Margins with Plant Delays**



Source: Castalia

Overall, it would be appropriate to conclude that examining investment commitments and plans indicates there is some risk that the market will fail to provide adequate security of supply in the future. However, from the available information we cannot tell the size of this risk, or the frequency and magnitude of any future under-provision. Also, as noted by some stakeholders during consultation, the decline of the energy margins

after 2014 may simply reflect the fact that some generation projects may simply not have been revealed to the market yet. Those submitters also noted that the decline in forecast energy margins assumes that some plant will be decommissioned before replacement units have been put in place—which is unlikely to happen in practice.

A few stakeholders argued that the current market structure provides a disincentive for adding new capacity because the prospect of shortages raises prices. These stakeholders argued that past pricing figures demonstrate windfall gains to generators and retailers through increases to contract prices during times of a higher risk of shortage, with the increases retained long after the risk of shortage passes. The opposing view, however, is that wholesale contract prices at any point in time are not related to the spot price, but are driven by the expected costs of new capacity to be added in the future. Those costs have been rising over the last 10 years, with prices for gas increasing due to cheap Maui gas running out and uncertainty over future gas supplies.

### 6.1.2 Types of Market Failure

In principle, it is important to distinguish between different kinds of market failure because the best policy response will depend on a clear diagnosis of the problem. For example, if the issue is specifically that the market does not deal well with the most severe dry years, then we would consider a response targeted to this specific failure. It is possible that the Whirinaki contract has already solved that problem for now and into the future.<sup>31</sup> On the other hand, if the market failure is more comprehensive, so that there is a pervasive risk to security of supply, then more fundamental additions to the market may be needed.

In this context, we suggest that market failure could fall into three broad categories:

- **Contingency-specific failure:** The market might not provide optimally for some specific contingencies, such as very dry years, but generally delivers sufficient resources to meet demand in all other circumstances.

The intuition is that markets do not deal well with low probability events. This may be exacerbated if the private loss to market participants from lost load in extreme circumstances is less than the social loss.

- **Periodic failure:** Market participants might, on average, provide sufficient resources to achieve the socially optimal security of supply (allowing for all contingencies) but are prone to error. For example, as load grows, investors may add capacity in time to meet additional demand and to maintain security of supply, but occasionally, unexpected construction delays might lead to periods of high risk of resource inadequacy. The particular concern is that the period of delay could coincide with a dry year.<sup>32</sup>

In themselves, errors are not a sign of market failure. In this case, a failure might arise if there is the difference between the private and social cost of the error. For example, while both investors and consumers benefit if new capacity is brought in just in time to meet load growth, the cost of delay to investors might be lower than it is to consumers.<sup>33</sup>

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<sup>31</sup> This is because the Whirinaki plant replaces periods of very volatile spot prices with a period of more stable prices when supplies are tight, thus giving more reliable signals to investors.

<sup>32</sup> If this happened the dry year would be exposing the security of supply problem but the underlying market problem would not be any particular inability to deal with the dry years.

<sup>33</sup> Spot prices might not rise fully to shortage levels during periods of demand restraints but may be high for sustained periods while there is a risk of shortages. It is not clear that there is any lack of incentives from the spot market.

In other words, if the private and social costs were perfectly aligned, the errors may be less frequent, as market participants incorporate the risk of delays into their plans and do not wait too long to bring on new capacity.

- **Systematic failure:** It may be that, on average and in general, the market fails to deliver adequate resources to achieve the socially optimal security of supply. Systematic failure would not mean **no** market investment, but rather that investment is consistently late relative to load growth. The result would be that the security margins are too low even in relatively normal years, let alone in extreme dry years.

Previously, when we defined resource adequacy, we drew a distinction between peak or capacity adequacy and energy adequacy, with the earlier related to ability to meet short-term peaks, while the latter was about ability to meet demand over a longer period of time.

The three categories of market failure may apply to both time dimensions. For example, in mainly thermal systems, concerns about contingency-specific or periodic failures relate to the market's ability to deal with short term peaks. In New Zealand, concerns have been expressed mainly, but not exclusively, about sustained adequacy.

Table 6.1 sets out this taxonomy of market failure, and provides some specific examples.

**Table 6.1: Examples of Possible Market Failures**

	Contingency Specific	Periodic Failure	Systematic Failure
<b>Capacity adequacy</b>	<ul style="list-style-type: none"> <li>▪ New Plymouth not made available due to unit commitment issues</li> </ul>	<ul style="list-style-type: none"> <li>▪ Delay to new plant with peaking capacity</li> </ul>	<ul style="list-style-type: none"> <li>▪ Generation investments delayed past the point where they are needed<sup>34</sup></li> </ul>
<b>Energy adequacy</b>	<ul style="list-style-type: none"> <li>▪ Insufficient thermal capacity for 1-in-60 dry year</li> <li>▪ Insufficient capacity if a large thermal plant has lengthy unexpected outage</li> </ul>	<ul style="list-style-type: none"> <li>▪ e3p delayed due to technical problems</li> <li>▪ Delays in resource consents for wind farms</li> </ul>	<ul style="list-style-type: none"> <li>▪ Generation investments delayed past the point where they are needed</li> </ul>

Source: Castalia

While at present we can not tell what kind of market failure (if any) we are observing, over time, market outcomes may reveal which of the three types of market failure is more likely. Below, we consider what would be the best corrective intervention for each market failure.

<sup>34</sup> The failure would be manifested in this case as insufficient offers overall into reserves and energy markets.

**Box 6.1: Stakeholder feedback on potential for market failure**

During consultation most stakeholders, including market participants and MEUG agreed with Castalia's conclusion that no evidence exists to demonstrate market failure. However, Grey Power and Ms. Melhuish argued that the current market structure provides a disincentive for adding new capacity because the prospect of shortages raises prices. Grey Power provided price figures that it argued demonstrated windfall gains to generators and retailers through increases to contract prices during times of a higher risk of shortage, with the increases retained long after the risk of shortage passes.

Source: Castalia

## 6.2 Intervention Options

Going forward, there is conceivably a risk that the market, left to its own devices, would not deliver the desired security of supply standard. Hence, some form of intervention might be justified.

Participants and commentators in the New Zealand energy market have proposed a range of options for ensuring provision of the required level of security of supply. These interventions have been developed as concepts, with varying levels of detail. While some of the proposals are based on capacity schemes actually in place in overseas jurisdictions, their adaptations to addressing the New Zealand energy adequacy problem have not been tested in practice as yet.

There is a wide range of options proposed for New Zealand conditions, but these models tend to share core features. Table 6.2 summarises the main features of various proposals and groups them according to their main characteristics. These characteristics include:

- The degree of centralisation of procurement—At the centralised end of the spectrum, the Commission identifies the need for reserve energy and undertakes all procurement. While at the decentralised end, the Commission sets the requirements, but load serving entities are free to procure as they see fit to meet those requirements
- Whether the intervention applies to 'missing energy' or all load—In the former case, the Commission identifies the gap between the desired security of supply standard and what the market is delivering, and fills the gap. In the latter, the Commission requires Energy Adequacy Hedges to cover all load. We use the term Energy Adequacy Hedge to describe generically a range of possible hedge instruments, such as forward contracts for energy (contracts for differences), energy call options and actual ownership of physical plant and fuel<sup>35</sup>
- Whether the intervention provides protection from high spot prices as well as additional energy, and

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<sup>35</sup> There is a serious debate to be had about whether financial hedges are enough, or whether they need to be physically backed. If financial penalties were adequate to cover the social cost of non-performance, then purely financial penalties might be enough. But, to make financial penalties at these levels enforceable would require huge performance bonds or capital adequacy requirements, which might not be enforceable. Hence, purely financial hedges might not provide comfort to the public or politicians, who might perceive the financial instruments as providing a way to gamble on New Zealand's energy security, without legally requiring physical plant and fuel. For these reasons most participants supported a 'physical' backing of the financial instruments, and we agree. However, as we explain below, these distinctions turn out to be not material to our recommendations.

- How the costs of the intervention would be recovered.

Overall, the various proposals converge to four broad types:

1. **Current Arrangement:** The current policy of procuring ‘missing’ energy as needed, perhaps with minor changes. This also includes the ‘watch dog’ option, under which the Commission would stand ready to intervene at the last minute if it becomes necessary, but would be ready to move to more comprehensive options if it becomes obvious that frequent and significant intervention is likely to be required
2. **Procure All Hedges:** Centralised tendering for Energy Adequacy Hedges covering all energy. This will involve rating all available generators for their capability to produce energy in a dry year (or in other relevant events, such as a windless year)
3. **Procure All Hedges with Opt-out:** Centralised tendering for Energy Adequacy Hedges for the proportion of load that load serving entities have not already hedged themselves. Those who choose to self-insure would need to demonstrate they are holding sufficient firm energy hedges to meet expected load in a dry year (or other relevant eventuality), and
4. **Market Augmentation:** A completely decentralised approach built around tradable obligations to hold Energy Adequacy Hedges. All load serving entities would be required to hold sufficient Hedges to meet their own expected load, or face significant penalties.

### 6.2.1 Description of Proposed Interventions

We now explain in more detail the proposals summarised in Table 6.2. More detail is provided in Appendix B.

#### Current Reserve Energy Policy

The current reserve energy policy involves the Commission determining the amount of energy capability that is required to maintain a specified security standard, and assessing whether existing plus planned new plant is sufficient to meet the requirement. If a gap exists between the two, the Commission may procure reserve energy (generation plant or contracted demand response capability) to manage the projected energy inadequacy.

While the New Zealand Government owns the Whirinaki reserve energy power station, the Commission is given the right to physically ‘call’ the plant to operate under the conditions specified in the Whirinaki offer strategy.<sup>36</sup> Both price and physical (Minzone) triggers are included.

#### Morrison & Co’s Enhanced Reserve Energy Proposal

In a review of the reserve energy scheme for the MED<sup>37</sup>, Morrison & Co suggested ‘enhancements’ to the then proposed reserve energy scheme.

The proposed enhancements operate at both planning and operational levels. The ‘planning’ aspect of the Morrison & Co proposal involves the Commission running a tender for reserve energy once a trigger point (defined in terms of the Minzone) has been reached. The tender is for the right to physically ‘call’ on the energy when the Minzone is reached. In return, providers would receive a pre-determined price for any energy

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<sup>36</sup> Whirinaki Power Station: Instructions to Offer Electricity, 2 November 2005

<sup>37</sup> Morrison & Co, 2004 *Issues Concerning the Reserve Energy Proposal*, Report to MED by John Culy, 22 January 2004

provided when called, as well as an annual fixed fee determined through the tender. Any new plant (or old plant that would otherwise be decommissioned) or demand side response would be eligible to tender. Auditing of capability and availability would be required.

Unlike the current reserve energy regime, there would be no requirement for the plant to be ring-fenced. The plant owner would retain the right to dispatch the plant as it saw fit at all times that did not affect the Commission's rights. There would be no reason why the plant could not be used to assist in other emergencies as long as spot prices signalled the problem. The Commission could on-sell the financial rights to power to the market (with proceeds offsetting the levy) but retain the physical dispatch rights.<sup>38</sup>

The Morrison & Co proposal allows for exempting from levy obligations those purchasers that self-provide security of supply with generating plant or via contracting.

**Table 6.2: Range of Potential Interventions to Ensure Adequacy**

	Description	Degree of centralisation	Proponent	Levy	Price hedge?
<b>1. Current Arrangement</b>	The Commission procures dry year call option on <b>specific energy quantity</b>	Centralised procurement	Existing reserve energy scheme	Universal charge, effectively on all consumers	No, apart from some price capping effect
<b>2. Procure All Hedges</b>	The Commission procures dry year Energy Adequacy Hedge for <b>all load</b>		M-co		Yes
<b>3. Procure All Hedges with Opt-out</b>	The Commission set Energy Adequacy Hedge requirement for <b>all load</b> , procures Energy Adequacy Hedge for <b>remaining un-hedged load</b>	Centralised procurement with opt out	Morrison & Co	Commission on-sells the hedges and recovers the net cost from un-hedged load	Yes, to the third party buyers of the hedges
			Contact/NE RA	Those who opt out and self-provide cover their own costs. The Commission levies un-hedged load	Yes
<b>4. Market augmentation</b>	Retailers and major users are required to procure Energy Adequacy Hedges for <b>all their load</b>	Decentralised procurement	WEMDG/C RA	No levy powers	Yes

Source: Castalia

<sup>38</sup> The Enhanced proposal also includes provision to tender for year-ahead 'coordination rights' that focus on ensuring efficient use of available resources within a potential dry year situation. We have concluded that this additional feature is not likely to be warranted. (See Section 9.)

## Other Energy Hedge Options

The remaining energy mechanisms are also structured as physically backed hedge contracts. Most are cap contracts or call options. A cap contract or call option is simply a hedge against prices exceeding a particular level. The examples considered here are:

- ‘Dry year reliability guarantee contracts’ (M-co).<sup>39</sup> Under this proposal, high strike price cap contracts are purchased by the Commission on behalf of all consumers. A quantity equal to expected winter demand is procured. The financial protection offered by the contracts is allocated to all wholesale buyers, and the costs of procurement allocated across the same parties
- ‘Dry year price insurance’ (Contact/NERA).<sup>40</sup> Under this proposal, obligations are imposed on purchasers to procure cap contracts. Any deficiency is procured by the Commission and the costs and contracts allocated to the relevant un-hedged purchasers, and
- ‘Dry year security hedges’ (WEMDG)<sup>41</sup> or adequacy tickets (CRA).<sup>42</sup> While these proposals are not the same, they are both examples of ‘fully’ decentralised mechanisms. Obligations are imposed on purchasers to procure cap contracts hedges. The Commission does not take on the role of procuring any residual contracts, but rather imposes high penalties for failure to comply with the hedging obligation.

The main difference between these options is the extent of central procurement (and therefore the ability to self-insure to avoid the levy allocation). All of the options include some degree of price protection: under the options with a decentralised component, purchasers may select the level of the cap (that is, the price protection level) that suits their risk management policies whereas under the centralised mechanisms, the level of the cap price is determined by the Commission.

### 6.3 Practicalities in Implementing Various Options

In moving from the first option (Current Arrangements) to the other three hedge-based options, the first major change would be a need systematically to assess all existing plants for their dry year capacity rating (DYCR) and to maintain this process as load grows over time. All options involving opt-out or trading of Energy Adequacy Hedges would also involve the need to determine and agree individual DYCRs for all generators. Given that significant money would be at stake, generators could litigate such assessments vigorously. Individual DYCRs will be complex and contentious. Complexities include river chain constraints, block dispatch and correlations between plant capabilities.

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<sup>39</sup> M-co, 2003, *Comparative Analysis of Reserve Energy Capacity Options*, Carl Hansen, 7 May 2003.

<sup>40</sup> Contact, 2003. A paper included in the Contact submission on the New Zealand Reserve Generation Proposal, NERA, June 2003.

<sup>41</sup> Appendix K of the WEMDG Draft Proposal March 1994.  
See also NZIER, 1995, *Mandatory Security Hedges: Implementation Issues*, Final Report to OCEP, prepared by John Culy, May 1995.

<sup>42</sup> CRA, 2005, *Motivating Electricity Sector Investment with Market Mechanisms* – draft report, January 2005.

**Table 6.3: Tasks Required under Key Mechanisms**

	Centralised options	Centralised options with opt out	Decentralised options
<b>Load forecasts</b>	Aggregate forecast required	Individual retailer or major user load forecast required	Individual retailer or major user load forecast required
<b>Determine energy required for security of supply standard</b>	Yes	Yes	Yes
<b>Determine DYCRs (or demand response)</b>	In aggregate, rather than needing to agree specific plant by plant ratings	Individualised. Rigorous process including audit & enforcement	Individualised. Rigorous process including audit & enforcement
<b>Audits of contracted plant availability (incl. fuel). Penalty regime for non-performance</b>	Yes	Yes. Must verify that purchasers' own contracts have penalty mechanisms	Must verify that purchasers' own contracts have penalty mechanisms
<b>Levy</b>	Levy all load	Levy un-hedged load	No levy

Source: Castalia

## 6.4 Framework for Evaluating the Options

All intervention options create some risk of distortion: that is of incentivising a less efficient generation portfolio and dispatch pattern than would have been possible without intervention, and hence increasing the overall costs of electricity. We refer to this as a **dynamic distortion**.<sup>43</sup> Each of the options also involves varying degrees of **transaction costs**. The overall objective is to solve the security of supply problem with least dynamic distortion and minimum transaction costs.

The benefits of an intervention will depend on the magnitude and frequency of market failure: in other words, on which of the types of the market failure outlined in Section 6.1.2 are working. Contingency specific market failure is least likely to occur frequently, and hence the benefit of correcting that market failure is likely to be the lowest. Periodic failure may be more frequent, and hence the benefits of correcting it would be greater. Correcting sustained market failure would involve the greatest benefit.

Overall, for a correcting mechanism to be considered, its costs must be lower than the benefit of correcting the likely type of market failure.

### 6.4.1 Dynamic distortions

The distortions that may be created by policy intervention fall into two categories:

- **Distortion to the generation mix** caused by procurement of energy call options from specific capacity (in particular, from open cycle gas turbines), and
- **Over-build of generation capacity** caused by procurement of excessive Energy Adequacy Hedges relative to what is needed to achieve the security of supply standard.

<sup>43</sup> That is, a distortion to dynamic efficiency, that related to investment and innovation.

In Table 6.4 we outline how the risk of causing each type of distortion varies between policy options.

The risk of distortion to the generation mix from procuring open cycle gas turbine capacity like Whirinaki is relatively limited, as long as little capacity is procured. The risk of this distortion rises if more such capacity is expected to be procured in the future. The proposition that the risk of distortion to generation mix is relatively low is contentious. For this reason, we explain our logic in arriving at this conclusion in some detail in Section 6.4.2 below.

The risk of over-build arises from the incentives faced by regulatory agencies in undertaking dry year capacity ratings. In essence, the implementation of comprehensive options would require the Commission to forecast load and the corresponding DYCR sufficiently ahead to allow for the full range of generation options to be brought forward. The costs of the Commission under-estimating the required level of energy hedges (or over-estimating DYCR of current and expected plants) will be transparent, and the political penalty high. On the other hand, the costs of over-estimating the required level of energy hedges (or over-estimating DYCR) would be invisible, and politically irrelevant. Hence, it is likely that the Commission would over-estimate risks, and the corresponding requirement for Energy Adequacy Hedges, and hence would promote over-build.

**Table 6.4: Options and Distortions**

	<b>Risk of Distortion to Generation Mix</b>	<b>Risk of Overbuild</b>
<b>Current Arrangements</b>	Relatively <b>high</b> if more reserve energy is procured just from open cycle gas turbines	Relatively <b>low</b>
<b>Procure All Hedges</b>	<b>Lower</b> risk of distortion since generation mix can be broader, but depends on how many years ahead the requirement is set	<b>Higher</b> than under Current Arrangements. The Commission needs to rate all plants more formally, hence may have incentive to rate overly cautiously because no opportunity for ‘last minute’ intervention
<b>Procure All Hedges with Opt-out</b>	<b>Lower</b> risk of distortion since generation mix can be broader, but depends on how many years ahead the requirement is set	<b>Moderate.</b> Risk of overbuild lower than in Procure All Hedges option because more incentive for market participants to challenge rating
<b>Market Augmentation</b>	<b>Lowest</b> since generation mix determined entirely by market, but depends how many years ahead the requirement is set	<b>Moderate.</b> Same risk as in Procure All Hedges with Opt-out option

Source: Castalia

In addition, more centralised options with opt-out and the decentralised procurement model would incur transactions costs in monitoring and enforcing individual load serving entities’ obligations, and arriving at an agreement on DYCR for each plant.

### The scale of over-build costs

As an illustration of the cost of surplus capacity, maintaining a two percent additional energy margin would correspond to an extra 800 GWh per year capability, say, 100 MW of additional capacity. Diesel-fired open cycle gas turbines probably cost less than \$1 million per MW. A more comprehensive plant mix would cost somewhat more.

#### 6.4.2 The distortion to the generation mix from Whirinaki

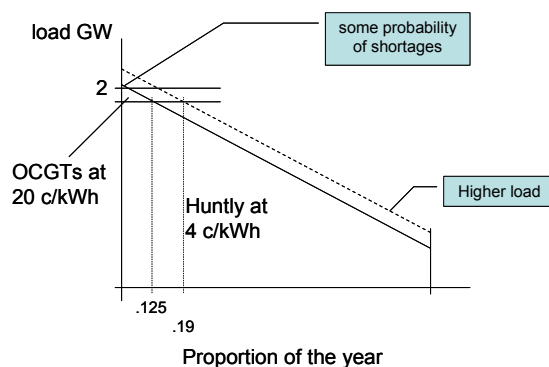
This section assesses the distortions arising from the Commission's procurement of diesel-fired open cycle gas turbines. When Whirinaki was procured for reserve energy, market participants expressed concerns that incentives for investment in lower merit order plant would be distorted. Incentives are changed because Whirinaki caps spot prices to some extent.

In our view, this distortion is temporary and modest. The reason is that any capping of spot prices is compensated for by an expansion in the utilisation of the open cycle gas turbine plants. After a brief period of adjustment as load grows, efficient incentives for investment in all lower order generation are fully restored. The residual distortion is that the plant mix has been skewed towards open cycle gas turbines. The cost of the residual distortion is a slightly higher total cost of supply.

#### Investment incentives reduced

Figure 6.3 depicts the load duration curve (LDC) for thermal plants allowing for hydro uncertainty.<sup>44</sup> The downward sloping curve can be thought of as the possible half hourly loads throughout the year, in the long run, ranked in size order. Equivalently, the curve is a cumulative probability distribution.

**Figure 6.3: Reserve Energy Plant and Investment Incentives**



Source: Castalia

The lower curve represents a supply and demand balance in which new 7 c/kWh baseload capacity is just economically justified, as well as some more open cycle gas turbine plant.

For additional open cycle gas turbine plant to be viable, the prices earned by generators during shortages (or in anticipation of shortages) must be high enough—and be

<sup>44</sup> The curve is the total LDC less all the base load contributions, namely run-of-river hydro, geothermal, cogeneration and wind generation, and also less the typical schedulable hydro contribution that is a combination of peak, mid level and baseload supply. The resultant thermal LDC is broadened (made steeper) to account for the variability in hydro inflows. This is the sort of curve one would expect by collecting all the thermal generation levels within a year but sampled over all inflow sequences.

happening often enough—to pay for the capital costs of the open cycle gas turbine plant, say \$85/kW/year.<sup>45</sup>

Now consider the case of 7 c/kWh baseload plant and assume that this plant has an operating cost of less than 4c. The plant will be scheduled below Huntly in the merit order. It will earn 4c for 87.5 percent of the time (while Huntly is on the margin), 15c for 12.5 percent of the time while diesel-fired open cycle gas turbines are on the margin, and—if spot prices are not capped—\$85/kW/year from higher spot prices. The \$85/kW/year contributes 1 c/kWh to the costs of the baseload plant.<sup>46</sup> The sum of all these components is 7 c/kWh, enough to make the incremental baseload plant profitable.

Now suppose that excess open cycle gas turbine capacity has been added so that spot prices are effectively capped. The 7c baseload plant is now not profitable because it is missing the 1c contribution from shortages or a risk of shortages.

### **Investment incentives restored**

What happens next? Demand grows, as shown by the higher LDC in the diagram. The utilisation of the open cycle gas turbine capacity will increase.

Suppose the utilisation of reserve energy plant increases so that it is on the margin for 19 percent of the time. As a result, the portion of the year for which Huntly is on the margin shrinks to 81 percent. Now the 7c baseload investor can expect 20c for 19 percent of the year and 4c for the remaining 81 percent, an average of over 7c. The incentive for investment in baseload is restored by a distorted use of the reserve plant.

### **What will happen next as demand grows further?**

As demand grows further, no more turbine plant will be justified unless demand becomes more peaky.<sup>47</sup> Baseload generation will be added to keep the turbine plant utilisation at 19 percent since this is enough to keep average capped prices above 7c. Keeping the turbine plant ‘pushed up’ in this way will, other things being equal, maintain the efficient contribution towards the cost of new baseload capacity. If there were unlimited expansion options at 7c, all future load would be met from this source.

As the cost of available baseload options increases to say 8 c/kWh (as we run out of the cheaper ones), the investment rate will slow relative to demand growth and the time that the open cycle gas turbines are on the margin (Huntly at capacity) will expand to around 25 percent. This will increase the average spot price to  $(0.25 \times 20c \text{ plus } 0.75 \times 4c =) 8c$ , not enough for more Huntly type plant (costing 9 c/kWh say), but enough for the higher cost baseload plant. The turbine plant may be worth expanding as well but it is not competing with the baseload expansion since it is not reducing average spot prices (spot prices are already capped).

When the zero-running-cost baseload opportunities have risen in cost to 11.2c, the open cycle gas turbine time on the margin will have risen to 45 percent. Then, more capacity of the 9c Huntly type will be as attractive as the other baseload options and both types might expand in parallel.

All through this process of escalating generation costs, the capping of spot prices maintains a constant presence, compensated for by the over-use of the turbine plant.

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<sup>45</sup> See page 38.

<sup>46</sup> \$85/kW/year divided by 8.76 MWh/kW/year, that is, \$10/MWh or 1 c/kWh.

<sup>47</sup> If the load increases proportionately, then more open cycle gas turbine plant will be needed to keep the probability of shortages down to the required level.

## Quantifying the cost

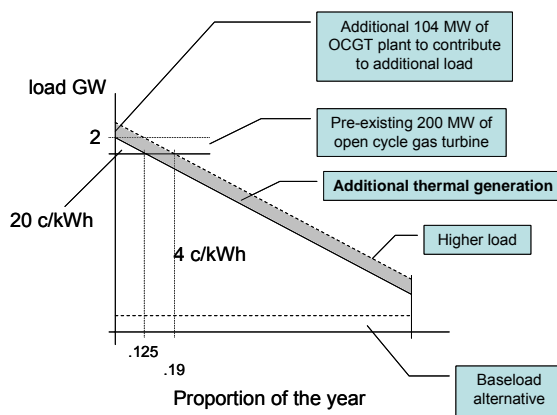
How costly might a continuation of the existing reserve energy policy be? To calculate the cost of another Whirinaki-type intervention, suppose (conservatively) that the optimal plant mix was now restored such that shortage prices were again providing the efficient \$85/kW/year incentive for new investment (1 c/kWh for baseload plant). As above, open cycle gas turbines would only need to be on the margin for 12.5 percent of the time to provide the appropriate incentive (along with Huntly) for new baseload plant.

If the Whirinaki exercise were then repeated and spot prices fully capped again (in the worst case), the time that open cycle gas turbines are on the margin would have to expand again to 19 percent.

Figure 6.4 gives a schematic representation of the altered generation pattern. Because of the capping of spot prices, a 7 c/kWh baseload option is not viable. It would have been with the 1 c/kWh contribution from shortage prices.

With this long run thermal load duration curve,<sup>48</sup> we estimate that load would need to grow by about 104 MW, say 911 GWh baseload, to move the time that the open cycle gas turbine is on the margin and setting prices from 12.5 percent out to 19 percent, thus restoring the average marginal cost. The 7 c/kWh baseload option would have provided this 911 GWh supply at a cost of \$64m per year.

**Figure 6.4: Dynamic Distortions from a Whirinaki-type Procurement**



Source: Castalia

Instead, as demand grows, the thermal plants are drawn on more extensively, as shown by the shaded area. The additional thermal generation is:

- 757 GWh from Huntly at 4 c/kWh, costing \$31m per year
- 114 GWh more from the existing open cycle gas turbine at 20 c/kWh, costing \$23m per year, and
- 30 GWh from new open cycle gas turbine plant, costing \$6m per year in fuel and \$9m per year in annualised capital costs.

With this generation pattern, the total cost is \$69 million per year, that is \$5 million per year more than with the baseload alternative that should have been built instead.

<sup>48</sup> Long run in the sense that it includes the hydro uncertainty.

## Summary

This \$5 million per year (say, \$70 million as a present value at 7 percent) is the order of magnitude of the cost associated with the Commission purchasing only open cycle gas turbine plant and offering it in at its SRMC. It arises because of the capping of spot prices. This is clearly only an approximate calculation but it flags the possibility that the distortion from focusing on just open cycle gas turbine plant may not be very serious.

The analysis above presents something of a worst case. It may well be that investors have been reluctant to count on dry year shortage prices to underpin new investment so the utilisation of open cycle gas turbines may be distorted upwards in any event. The block of reserve energy priced at a known level may in fact be shoring up investment plans.

In this worst case, our calculations indicate that about two years of load growth—that should have been met by new 7 c/kWh baseload plant—would instead be met by additional output from higher cost thermal stations. If Whirinaki can be scrapped, this distortion remains an on-going issue. If Whirinaki remains until it is retired, the distortion is now a sunk cost, unless more reserve energy is procured as open cycle gas turbines when other options would be lower cost. By now, any capping effect of Whirinaki will have been cancelled and appropriate investment in mid level and baseload will have resumed.

### 6.4.3 Matching solutions to market failures

To sum up, the appropriate solution depends on the type of market failure (which defines the benefits of intervention), and on the likely distortions caused by that intervention. We summarise the relationships in Table 6.5

**Table 6.5: Matching Solutions to Market Failures**

	Contingency specific market failure	Periodic market failure	Systematic market failure
<b>Current Arrangements</b>	<ul style="list-style-type: none"> <li>▪ <b>Low</b> cost of generation mix distortion due to limited nature of problem</li> <li>▪ <b>Low</b> risk of over-build due to ‘stand-by’ nature of intervention</li> <li>▪ <b>Low transactions costs</b></li> <li>▪ <b>Low benefit:</b> problem may have been solved</li> </ul>	<ul style="list-style-type: none"> <li>▪ <b>More</b> frequent intervention likely, hence greater risk of generation mix being affected. <b>Medium</b> risk of generation mix distortion</li> <li>▪ <b>Low</b> risk of overbuild</li> <li>▪ <b>Medium transactions costs</b></li> <li>▪ <b>Medium benefit</b></li> </ul>	<ul style="list-style-type: none"> <li>▪ Sustained intervention likely to substantially affect generation mix. <b>Highest</b> cost</li> <li>▪ <b>Lowest</b> risk of over-build</li> <li>▪ <b>High transactions cost</b> current arrangements due to frequent tendering</li> <li>▪ <b>High benefit</b> of solving this market failure</li> </ul>
<b>Procure All Hedges</b>	<ul style="list-style-type: none"> <li>▪ <b>Low</b> cost of generation mix distortion due to tendering</li> <li>▪ <b>High</b> cost of over-build due to comprehensive intervention</li> <li>▪ <b>Medium transactions costs</b></li> <li>▪ <b>Low benefit</b></li> </ul>	<ul style="list-style-type: none"> <li>▪ <b>Low</b> cost of generation mix distortion due to tendering</li> <li>▪ <b>Medium</b> cost of over-build due to more pervasive problem</li> <li>▪ <b>Medium transactions costs</b></li> <li>▪ <b>Medium benefit</b></li> </ul>	<ul style="list-style-type: none"> <li>▪ <b>Low</b> cost of generation mix distortion due to tendering</li> <li>▪ <b>Lowest</b> cost of over-build as market would consistently under-provide</li> <li>▪ <b>Medium transactions costs</b></li> <li>▪ <b>High benefit</b></li> </ul>
<b>Procure All Hedges with Opt Out</b>	<ul style="list-style-type: none"> <li>▪ <b>Low</b> cost of generation mix distortion due to opt out</li> <li>▪ <b>High</b> cost of over-build due to comprehensive intervention</li> <li>▪ <b>High transactions costs</b></li> <li>▪ <b>Low benefit</b></li> </ul>	<ul style="list-style-type: none"> <li>▪ <b>Low</b> cost of generation mix distortion due to opt out</li> <li>▪ <b>Medium</b> cost of over-build due to more pervasive problem</li> <li>▪ <b>High transactions costs</b></li> <li>▪ <b>Medium benefit</b></li> </ul>	<ul style="list-style-type: none"> <li>▪ <b>Low</b> cost of generation mix distortion due to opt out</li> <li>▪ <b>Lowest</b> cost of over-build as market would consistently under-provide</li> <li>▪ <b>High transactions costs</b></li> <li>▪ <b>High benefit</b></li> </ul>
<b>Market Augmentation</b>	<ul style="list-style-type: none"> <li>▪ Lowest cost of generation mix distortion due to market solution</li> <li>▪ <b>High</b> risk of overbuild</li> <li>▪ <b>High transactions costs</b></li> <li>▪ <b>Low benefit</b></li> </ul>	<ul style="list-style-type: none"> <li>▪ Lowest cost of generation mix distortion due to market solution</li> <li>▪ <b>High</b> risk of overbuild</li> <li>▪ <b>High transactions costs</b></li> <li>▪ <b>Medium benefit</b></li> </ul>	<ul style="list-style-type: none"> <li>▪ Lowest cost of generation mix distortion due to market solution</li> <li>▪ <b>Lowest</b> cost of overbuild as market would consistently under-provide</li> <li>▪ <b>High transactions costs</b></li> <li>▪ <b>High benefit</b></li> </ul>

Source: Castalia

## 6.5 Cost Benefit Analysis Under Uncertainty

As we explained above, there is insufficient information to conclude what the exact nature of the market problem is, or indeed if there is a problem. In part, this is because the current policy settings have not been around for long enough to draw conclusions and because we have no way of reliably distinguishing between firm investment plans and broad intentions.

It would be a mistake to pretend that problems can be identified with certainty. Rather, it is important to recognise uncertainty, and to build the Regime on effectively addressing that uncertainty.

This has two implications:

- First, the Regime needs to evolve as new information becomes available. Hence, it is important to identify markers which should prompt specific actions, and
- Second, the Regime needs to recognise the likelihood of errors. The Regime should aim to minimise the overall cost resulting from such errors.

**Table 6.6: Cost of Errors**

	<b>Contingency Specific Failure</b>	<b>Periodic Failure</b>	<b>Systematic Failure</b>
<b>Type 1 Error: intervene when should not</b>	<ul style="list-style-type: none"> <li>▪ Excess investment</li> <li>▪ Distortion</li> <li>▪ Medium cost</li> </ul>	<ul style="list-style-type: none"> <li>▪ Could undermine market's error correction mechanism</li> <li>▪ Medium cost</li> </ul>	<ul style="list-style-type: none"> <li>▪ Transaction and market design costs</li> </ul>
<b>Type 2 Error: do not intervene when should</b>	<ul style="list-style-type: none"> <li>▪ Too late to take action when contingency occurs</li> <li>▪ High cost</li> </ul>	<ul style="list-style-type: none"> <li>▪ Low cost interventions possible: e.g. pre-consented sites</li> <li>▪ Medium cost</li> </ul>	<ul style="list-style-type: none"> <li>▪ Have time to see how the investment pattern develops</li> <li>▪ Low cost if watch development carefully</li> </ul>

Source: Castalia

Overall, we should aim for a policy that minimises the sum of errors, and gives the Commission the greatest option to keep interventions to a minimum to begin with, but to correct errors in the future if necessary. Given uncertainty, an important element in deciding what constitutes the best policy is how long the Commission can keep its options open so that it is physically able to act after a market failure has become apparent, but before it is too late. If the Commission acts too early—that is, before market failure becomes apparent—it is itself likely to induce some degree of market failure by crowding out commercial investments.

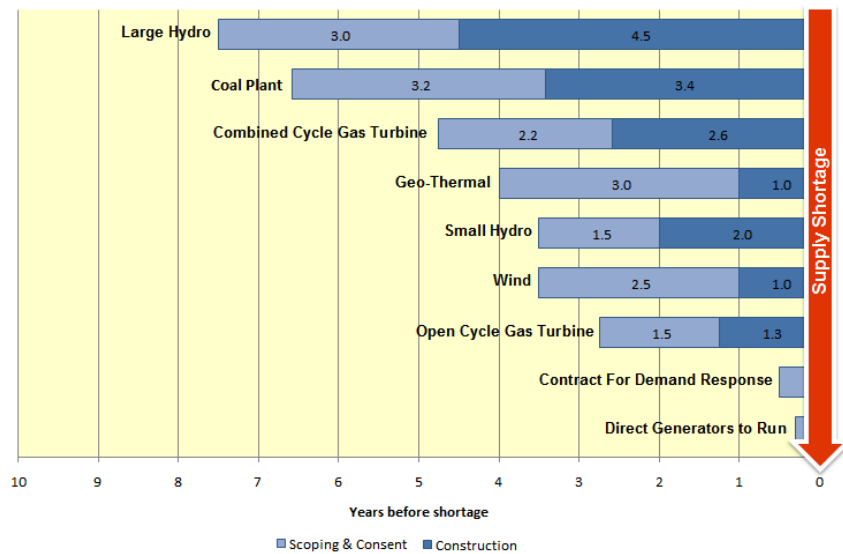
Figure 6.5 below shows the lead times for procuring different types of energy, whether through additional generation or demand response. This suggests that contracted demand response and Open Cycle Gas Turbines—the type of energy the Commission is likely to procure—would have shorter lead times than the types of plant market participants would likely invest in. The lead time would be shortened further if the sites

were ‘pre-consented’. This suggests it is reasonable to think that the Commission could make a policy of being the ‘watch dog’ with ‘just in time’ interventions, work in practice.

During consultation it was suggested that the Commission could be given powers to force thermal generation to run. This is premature in our view, given that our analysis in Section 9.2.1 shows that thermal generation is likely to be dispatched in an appropriate manner by market participants without intervention.

If the Commission is able to act faster than the market participants, then the current regime allows it to delay intervention as long as possible, and only to intervene when it is fairly obvious that intervention is required. If the market failure is specific to the dry year problem, then no further intervention is likely to be needed, and the only cost would be the cost of on-going monitoring. Since Whirinaki is already built, and its cost is sunk, the historic distortion to the generation mix associated with it is no longer relevant. If the problem is periodic market failure, the Commission will have an option of deciding the best way to deal with the particular market errors which may emerge. For example, if the problem is caused by construction delays, demand management may be the least cost option. At worst, there may be cause to build further open cycle gas turbine capacity, which would somewhat increase the cost of distortion to the generation mix.

**Figure 6.5: Lead Times for New Reserve Energy**



Source: Castalia

If the market failure turns out to be sustained and systematic—unlikely as it is—this will become obvious due to the frequency and scale of intervention needed, and at that point, the Commission will have the option of introducing a more comprehensive solution.

All comprehensive solutions (both centralised and decentralised hedge mechanisms) carry a risk of promoting excess capacity. The mechanisms require the Commission to impose requirements on the market sufficiently far into the future so that market participants are able to build various kinds of additional capacity if it is needed. If the Commission wants to avoid distorting the generation mix, the effective lead time needs to be long-enough to accommodate all technology options, such as seven or more years for large hydro.

Acting this far in advance, the Commission will need to take account of the likely error in forecasting load. Since the Commission will no longer have an option of last minute *ad hoc* intervention, it may be more concerned about the risks of ‘under-shooting’ security of supply that far into the future, rather than ‘over-shooting’. Hence, it will likely be risk averse, and will tend to promote over-build.

So, if the market failure is specific to the dry year, comprehensive solutions will have imposed over-build and high transactions costs for no particularly good reason, as that problem has most likely been fixed and any distortion associated with Whirinaki is now largely a sunk cost. If the market failure is periodic, the transactions cost and the cost of overbuild associated with comprehensive options is again higher for that kind of problem than the mild distortion to the generation mix associated with another Whirinaki. Comprehensive measures are appropriate for sustained market failure, but we always have an option to introduce them if the sustained failure is revealed.

Overall, since we do not know what kind of failure—if any—we are dealing with, the current regime (with enhancements proposed in subsequent sections) is the right path forward. This path is most likely to minimise the sum of errors and allow the Commission to wait for new information before making any new and substantial changes.

**Box 6.2: Stakeholder feedback on achieving the desired standard**

Stakeholders mostly agreed that there is no evidence to suggest that the market will fail to deliver security of supply to the desired standard (Generators/Retailers and MEUG). However, Grey Power and Ms. Melhuish were more sceptical. Grey Power submitted that, in addition to the ‘watch dog’ role, it may be useful to allow the Commission to force thermal generators to run in the early stages of a potential shortage. Ms. Melhuish favoured a market augmentation approach and a fundamental review of the market to allow consumers (both large and small) to more actively participate in the market.

Source: Castalia

## 7 Recovering the Costs of Achieving the Defined Security of Supply Standard

The GPS requires this Review to assess whether the reserve energy levy arrangements should be changed. The costs of Whirinaki are at present recovered from consumers via a small uniform levy. We recommend that the existing levy mechanism should be retained for the present assets. If the Commission finds that it has to intervene again to buy more reserve energy, we recommend that this cost also be recovered by a universal levy. We anticipate that if this further intervention happens, the Commission will move to providing or requiring energy adequacy hedges. In all the proposed schemes in which the Commission procures energy adequacy hedges, costs are recovered just from those on whose behalf the Commission has acted.

This section sets out the reasoning behind these conclusions by:

- Outlining the current arrangements
- Describing the requirements to review the current funding approach and the issues raised in deciding on the current approach
- Explaining the logic for preserving the current levy for the current reserve energy interventions, and
- Analysing the approach that should be applied to funding any additional reserve energy provisions in the future.

### 7.1 Current Arrangements

Paragraphs 62 and 63 of the GPS require the Commission to recover the net costs of reserve energy using a levy that applies to all consumers based on wholesale purchases on an equal basis. Net costs are capital and operating payments for the reserve energy less spot market income from it.

The costs of running Whirinaki appear to be around \$27 million per year.<sup>49</sup> The levy is charged to all spot market purchasers of electricity on a \$/MWh basis. The invoiced levy rate for system security operations (which includes reserve energy) for the 2006/2007 year was \$0.6536/MWh.<sup>50</sup> The levy is passed through to consumers.

### 7.2 Review Requirements

In 2003, MED consulted on proposals to recover security of supply costs (including reserve energy costs) through a simple levy on wholesale purchasers.<sup>51</sup>

A number of parties responded that exemptions from the levy should be allowed where security of supply is self-provided.<sup>52</sup> In particular, consideration was given to whether the Comalco contracts should be exempt from the levy to the extent that Comalco has its own arrangements for supply security.<sup>53</sup> However, the MED, after considering whether

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<sup>49</sup> [http://www.med.govt.nz/templates/MultipageDocumentPage\\_6516.aspx](http://www.med.govt.nz/templates/MultipageDocumentPage_6516.aspx)

<sup>50</sup> Notice of Annual Levy Rates for the Financial Year Ending 30 June 2007, available at <http://www.electricitycommission.govt.nz/pdfs/rulesandregs/reg/pdfsregistration/levy-rates-july-2006.pdf>

<sup>51</sup> <http://www.med.govt.nz/upload/24596/discussion-paper.pdf>

<sup>52</sup> Para 17 [http://www.med.govt.nz/templates/MultipageDocumentPage\\_6488.aspx](http://www.med.govt.nz/templates/MultipageDocumentPage_6488.aspx)

<sup>53</sup> The Comalco contracts have some unique characteristics, and the parties to them are already subject to specific exemptions in relation to part C and G of the Rules. However, other submitters considered the Comalco situation to be no different to that of other consumers' arrangements to manage business risks associated with supply security,

an exemption regime could be developed, concluded that this approach, which would require exemption requests to be processed prior to determining the levy rate, would involve considerable administrative complexity and cost. One issue was the difficulty in comparing different forms of supply security based on contracts with different price structures, periods, and force majeure and other risk allocation provisions. MED determined that, in view of the complexities involved in designing an exemption regime, such work is better undertaken as part of the comprehensive review of the Commission's security of supply policy.

Paragraph 66 of the GPS requires that the levy arrangements be reviewed as part of the independent reserve energy review. Recommendations should be made as to whether alternative levy arrangements would produce a fairer and more efficient outcome. In particular, the review should investigate whether to allow for some element of self-provision of security of supply with an associated exemption from the levy, and if so whether the extent of any self-provision should be audited by a body independent of the Commission.

### 7.3 The Existing Levy

We see no basis for changing the levy that is recovering the costs of Whirinaki. Our reasons are as follows:

- The process of sharing the costs amongst loads to the extent they were not hedged would be complex to implement—as found by the MED review—especially retrospectively. One would have to value the hedge that was actually provided by Whirinaki and rate all the hedges held at the time
- The plant cost is now largely sunk so we see no signalling role for the existing levy. If the costs of Whirinaki are recoverable, then there may be a signalling role. However, the efficient hedge price that should be applied to un-hedged load would bear no relationship to the price required to recover the Whirinaki costs. In all likelihood, there would still be a need for a universal levy
- Retailers and major users who at the time were already adequately hedged, will have lost some value in their existing hedges but will often have had some opportunity to trade to readjust their position
- A shift to recovering Whirinaki costs through general taxation is unwarranted. Reserve energy is not a public good. The beneficiaries of reserve energy—and other Commission functions—are electricity consumers not tax payers in general, even though there is a strong overlap, and
- Appealing to fairness seems inconclusive here:
  - The uniform levy is clearly unfair to fully hedged major users, but
  - Reallocating the costs just to those loads that were less hedged at the time would seem unfair because they were given no opportunity to 'opt out' by hedging more themselves.

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e.g. owning onsite generating plant, or entering into financial hedging contracts. It was also questioned whether this type of consumer will still benefit from the Commission's role in ensuring security of supply to a 1-in-60 dry year standard, as they will face a lower probability of supply interruptions than would otherwise be the case, and may face lower spot prices. [http://www.med.govt.nz/templates/MultipageDocumentPage\\_6519.aspx](http://www.med.govt.nz/templates/MultipageDocumentPage_6519.aspx).

## 7.4 Future Interventions

Should the levy be changed for any future procurement of reserve energy? We think that so long as future interventions are similar to the past intervention, there is no clearly better way of funding the intervention than the current levy. If significant new reserve energy investments are needed on a continuing basis, then a new policy would be warranted.

In Section 6 we explain why we think there may be no need for the Commission to procure reserve energy again. There is a good chance that the market will maintain what are seen as adequate margins—especially if the standard is modified—and Whirinaki may have resolved any specific dry year problem. If, however, forecasts of the energy margin drop below the required standard within the lead time for new generation, intervention may be required. If there are no obvious explanations like a project delay, the reduced margin may signal the more systematic market failure discussed above and the Commission may choose to implement one of the energy adequacy hedge proposals. But to deal with the immediate problem at that time, the Commission may have to intervene ‘once more’.

If at that time the Commission decided to buy more diesel-fired open cycle gas turbines, the price capping effect of the new plant would be anticipated by the market and hedge positions would adjust accordingly. There would seem to be no natural basis for allocating the costs amongst load and no guarantee that any differential charge would be efficient. We conclude that there would be no alternative but to repeat the same universal levy for this intervention.

If, at the same time as it is procuring more reserve energy, the Commission decides to adopt one of the energy adequacy hedge mechanisms, the levy question will be largely determined by the decision made on the energy adequacy hedge mechanism:

- In Procure All Hedges options, where the Commission procures energy adequacy hedges on behalf of all load, a universal levy would apply
- In a market reserve energy-design option, where retailers and major entities are required to hedge themselves, there would be no levy, and
- In the partially centralised options with opt-out, the Commission would be buying hedges competitively on behalf of unhedged loads, would allocate the benefits of those hedges to those loads and would recover the costs from those loads.

## 7.5 Summary

We believe the requirement for a review of the levy was included in the GPS prescription for this Review because it was at that time regarded as possible that the Commission would be intervening regularly. If such regular intervention is required, then we would recommend moving away from the current direct procurement process to an energy hedge adequacy requirement. If we move to an energy adequacy hedge requirement, the levy debate will largely fall away.

**Box 7.1: Stakeholder feedback on levy arrangements**

Meridian, Genesis and TrustPower supported retaining the current levy arrangements, although TrustPower noted that its support is mainly due to a lack of a practicable better alternative. Transpower submitted that self-provision of security of supply should be taken into account in the levy arrangements. (As noted above, this approach would be complex and costly and is not warranted in our view).

MEUG argued that the market is providing an adequate level of security of supply—Whirinaki, therefore, is not needed and should be sold, thereby removing the need for a levy. MEUG also submitted that Whirinaki, if retained, would mainly exist to manage the Government's political risk, rather than benefiting customers. Therefore, MEUG argued that the costs of Whirinaki should be funded through taxation.

Contact Energy also noted that the current levy arrangements are suboptimal but did not suggest an alternative. Ms. Melhuish argued that under her preferred market augmentation approach the levy would not be needed.

Source: Castalia

## 8 Scopes of Regime and Policy

As noted in Section 2, the Regime as currently set out, is detailed and prescriptive, leaving little flexibility to the Commission on how it can develop a Policy to implement the Regime. During consultation, most stakeholders noted this was likely the result of the perceived need for immediate action at the time the Arrangements were introduced. At that time, enacting a Regime that provided detailed instructions helped give the newly formed Commission clarity on how to deal with the security of supply issues at hand.

While it is important for the Commission to be able to base its policy on clearly articulated principles and objectives, an overly prescriptive Regime may not be durable or effective. As the electricity sector evolves, so do the issues related to security of supply, and methods for dealing with those issues. An overly prescriptive regime could quickly become outdated and require significant and regular revision. For example, at the time the Arrangements were enacted, the biggest threat to security of supply was clearly an energy shortage due to dry years. At present, constrained transmission into particular regions (which makes it difficult to ensure peak demand in those regions is met) may be a more significant threat to security of supply.

More importantly, a clear delineation is needed between the respective roles of primary legislation (the Act), regulations (the Regime) and the practical implementation of both (the Policy). In our view, legislation should define, at a principle level, the objective that must be achieved by the Commission. The Regime should then translate the legislative objective into clear regulatory settings. These settings should:

- Explain how the high-level legislative objective should be interpreted by providing more detail, including quantifying the objective where possible
- Define and set clear boundaries on the powers that the Commission can use to achieve the objective (including any ability to impose costs on market participants either directly or by compelling them to act in a certain way), and
- Leave all other details to be defined in the Policy, thus allowing the Commission maximum operational flexibility, subject to the two bullet points above.

This approach will help to ensure that:

- The regulatory objective is clear to the Commission and market participants alike
- The Commission, as an expert regulatory body, is given appropriate operational flexibility to achieve the regulatory objective in the most effective way, and
- Market participants have clarity and certainty with respect to the sort of costs the Commission can impose in order to achieve the objective, without the need for additional regulations to be introduced by Government.

The current framework differs from this approach because the Regime, in translating the legislative objective, goes much further than simply defining a quantitative objective and the boundaries of the Commission's powers. The more detailed, operational aspects of the Arrangements, which are currently set out in the Regime, should therefore be delegated to Policy level. The Commission could then define and review these detailed aspects as needed and, if warranted, make changes to the Policy, without the need for

Government involvement to change the Regime. This approach would help create a more stable investment environment for market participants.

We therefore recommend that:

- The Regime should focus on:
  - Defining an operational standard of security of supply that should be achieved. This is currently defined as ensuring security of supply in a 1-in-60 dry year, without the need for conservation campaigns. If our recommendations are accepted, it could instead be defined in terms of an expected level of un-served energy and implemented as an energy margin, probably around 15 percent
  - Defining the Commission’s powers to intervene in the market and compel market participants to act. These powers currently include:
    - Contracting for reserve energy and dispatching it into the market to ensure security of supply
    - Levying market participants for the cost of providing reserve energy.
- All other operational detail should be left for the Commission to define as part of the Policy, including:
  - The way in which security of supply levels should be measured and monitored
  - The trigger and process for any intervention, such as procuring or dispatching reserve energy, and
  - The form of intervention (for example, the type of reserve energy to be procured and the structure of any payments to the providers of reserve energy), subject to the intervention being within the scope of powers defined in the Regime.

This alternative reallocation of scope would make the Arrangements more effective and durable.

**Box 8.1: Stakeholder feedback on the scopes of the Regime and the Policy**

All stakeholders, with the exception of Ms. Melhuish, generally supported our recommendations regarding the scope of the Regime and the Policy. Ms. Melhuish favoured a market augmentation approach that would require fundamental changes to the Arrangements and therefore she did not agree with our recommendations, which deal mostly with improving the current Arrangements.

## 9 Improving the Policy under the Current Regime

This section reviews the detailed operation of the current Policy, and suggests ways in which it could be improved. It focuses in particular on:

- The definition and operation of the Minzone
- The approach to procuring reserve energy
- The way in which reserve energy is despatched
- How the Commission provides the market with information
- How conflicts of interest are managed, and
- Approaches to managing security of supply once the system moves into a shortage.

### 9.1 Overview of Current Policy

The Objective of the current Policy is:

*Expected Supply under a 60 year return period drought (of any duration) will be sufficient to meet Expected Demand without the need for emergency intervention.*

- *Expected Supply will be simulated using:*
  - *Design 1 in 60 year inflow sequences scientifically derived from historical inflow data*
  - *An assumption that all non-hydro plant is fully available up to its expected availability after accounting for planned and random outage factors and the impact of transmission and fuel deliverability constraints*
- *Expected Demand will be based on scientific forecasting methods and intelligent information gathering processes. This will include:*
  - *The use of econometric forecasting techniques*
  - *Analysis of demand trends in different regions*
  - *Analysis of the trends in key consumer segments of the energy sector*
  - *Analysis of the expected demand response to spot price*
- *Expected Supply and Expected Demand will be assumed by the Commission and will be reviewed at least every six months and revised to reflect the best information available.*
- *Non-hydro plant will include all thermal, geothermal and cogeneration plants, and all wind farms.<sup>54</sup>*

The general approach adopted by the Commission in the Policy involves:

- A strong focus on providing information and analysis to the market, to maximise opportunities for market participants to manage security of supply risks
- Monitoring long-term security of supply and publishing forecasts to assist risk management and investment decisions. The aim is to avoid reserve energy procurement by the Commission

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<sup>54</sup> Section 1 of the Initial Security of Supply Policy.

- Assessing security of supply in the medium term and determining the need for reserve energy to be contracted if sufficient demand side and new generation initiatives are not forthcoming from the market
- Delaying any decision to procure reserve energy for as long as possible, maximising the opportunity for market solutions
- Monitoring short-term security of supply and regularly publishing the Minzone to encourage participants to adequately manage short-term security of supply
- Monitoring market response to the security of supply situation and publishing expectations of outcomes that would be consistent with ensuring the security of supply standard is met. This includes checking whether all non-hydro plant is operating at levels consistent with the underpinning Minzone assumptions at times when storage is near to, at or below the Minzone, and
- Triggering reserve energy dispatch if the Minzone is breached, unless reserve energy has already been dispatched due to spot prices exceeding the price trigger.

The Commission is also undertaking work on Emergency Response Plans (ERPs) to ensure proper coordination during years with a worse than 1-in-60 inflow sequence. The ERP also deals with how the total costs of any forced rationing can be reduced by, for example, seeking to allocate any forced rationing to customers with a generally lower VoLL. The Commission is also continuing work on understanding the stochastic properties of inflows. This will help develop a probabilistic approach to estimating security of supply levels.

## 9.2 The Minzone

The Minzone is a key concept around which the Policy is built. The Regime requires that, as part of its Policy, the Commission should:

*...develop and publish a minimum hydro zone giving its estimate of minimum hydro storage levels required at different times of the year to avoid the risk of shortages in a 1 in 60 dry year. This minimum zone should take into account the expected availability and use of thermal generation. The minimum hydro zone should not be catchment-specific but should be national or based on regions defined by likely transmission constraints during a dry hydro period...*

The Commission regularly publishes and updates its Minzone analysis, which tracks actual hydro storage relative to the Minzone. This analysis is currently used as the main measure of New Zealand's actual security of energy supply at any point in time.

In the sections below we discuss some of the key underlying assumptions on which the Minzone is based, as well as stakeholders' perceptions of the Minzone analysis.

### 9.2.1 Dispatch of thermal generators within Minzone

The above policy requires *"This minimum zone should take into account the expected availability and use of thermal generation."* Therefore, an underlying assumption for the Minzone (which in turn affects the procurement and dispatch of reserve energy) is that, once the Minzone is breached, the market will adjust to ensure thermal generation operates to conserve hydro storage. In order for this assumption to hold, once the Minzone is breached, the marginal value of water must exceed the short run marginal cost (SRMC) of the highest-priced thermal generator. That is, hydro generator offer prices must exceed

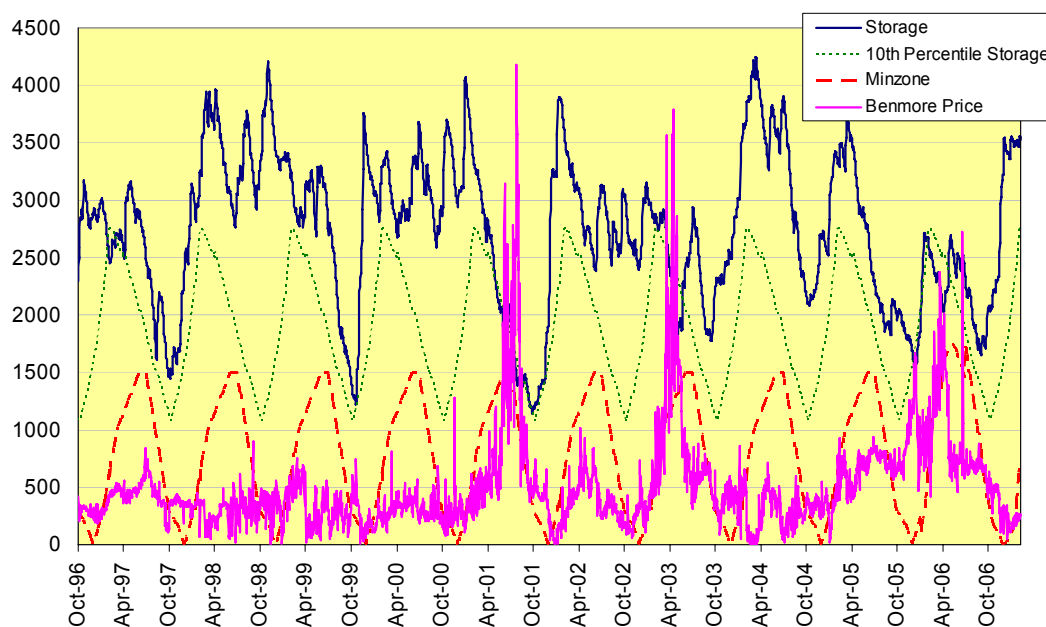
thermal generator offer prices thus ensuring that all thermal generation will be fully dispatched.

This section examines whether, once the Minzone is breached, we can be confident that marginal water values will always be above the SRMC of the highest priced thermal generator and thus ensure all thermal generation is fully dispatched.

We conclude that there is a small but definite risk that during the months March to August the marginal water values may not be sufficiently high to guarantee full dispatch of all available thermal generation within the upper part of the Minzone. It is likely that this reflects the conservative nature of the Minzone. By this we mean that the Minzone is based on an absolute security standard, rather than an economic security standard, and a limited set of specific inflow sequences, rather than the overall probability of a set of inflow sequences. Hydro-generators' own assessments of the risk of energy shortages may be less conservative, and this may lead hydro-generators to submit bids that in some cases result in their plant being dispatched ahead of thermal plant, even when the Minzone has been reached.

To investigate whether these assumptions are valid, we attempted to determine how the marginal value of water changed as the hydro storage level approached the Minzone.<sup>55</sup>

**Figure 9.1: Observed spot prices as a function of storage**



Source: Castalia

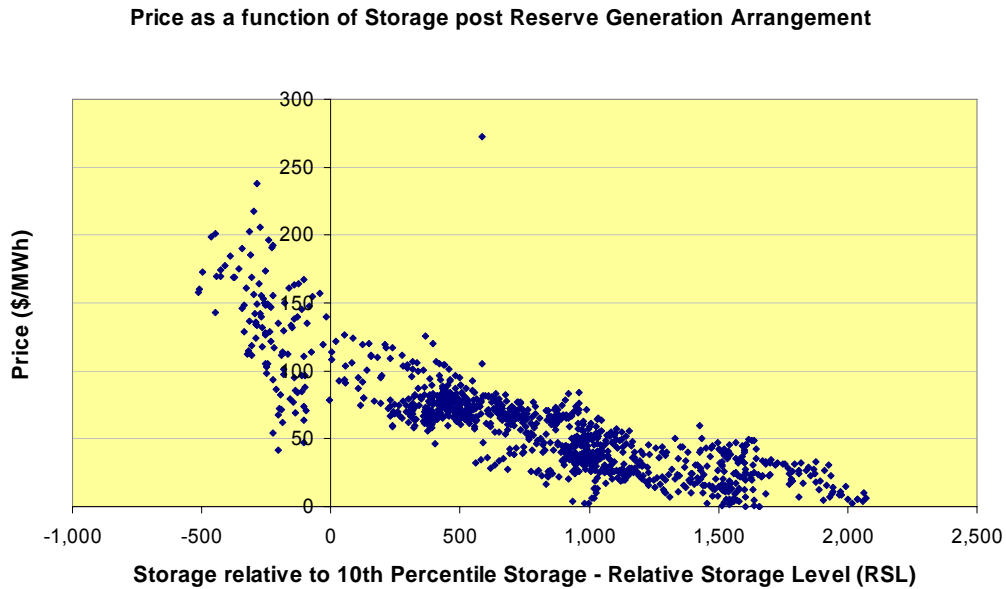
Following the approach developed by Tipping, McNickle and Read,<sup>56</sup> we tracked the relationship between observed spot prices and relative storage level (RSL) as an indicator of how hydro generators value their storage. The RSL is taken against a baseline of the 10<sup>th</sup> percentile storage level for that time of year. That is, rather than look at absolute

<sup>55</sup> As, since the creation of the Minzone, storage has never declined below the Minzone, we focused our analysis on data relating to dates on which storage was closest to the Minzone.

<sup>56</sup> [http://www.mang.canterbury.ac.nz/people/jimbo/James\\_Tipping\\_EPOC\\_WW\\_2005.pdf](http://www.mang.canterbury.ac.nz/people/jimbo/James_Tipping_EPOC_WW_2005.pdf)

storage level we examined storage relative to some indicator of how generators normally manage storage for that time of year. Underlying this approach is an assumption that generators manage their storage levels, and prices, based on expected inflows and demand for the remainder of that year, or at least until the lakes are expected to fill again. By adopting a ‘relative’ storage level approach, we are able to separate out the time element of water values. Thus we can plot price as a function of RSL independent of time. Figure 9.2 shows Benmore prices on this basis.

**Figure 9.2: Observed spot prices as a function of relative storage level (RSL)**



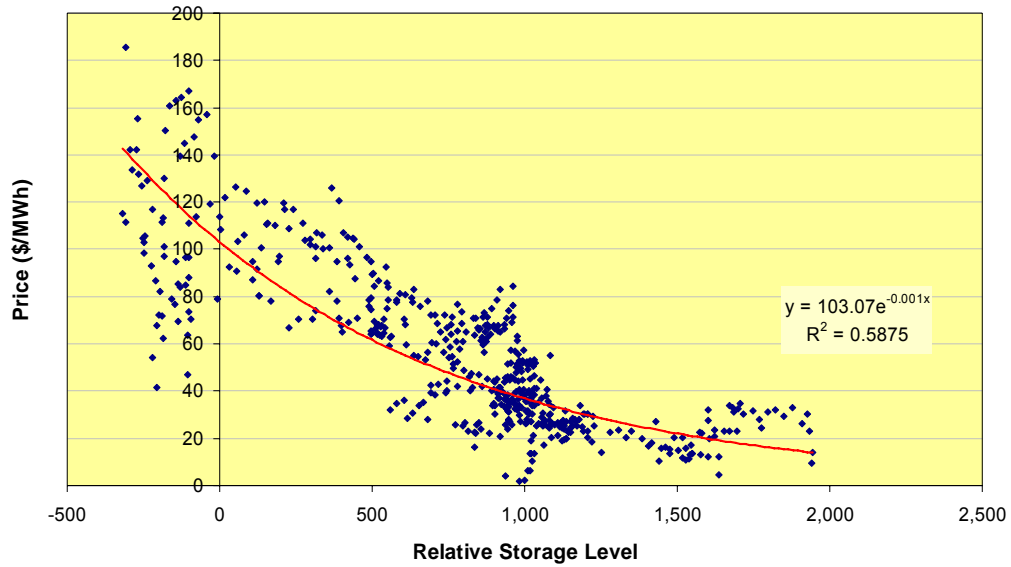
Source: Castalia

Our analysis covers the period from the commissioning of Whirinaki on 1 June 2004 until now. This is appropriate, in our view, as generators may have changed their behaviour to reflect the presence of reserve energy in the form of Whirinaki.

This period was further split into two seasons—warm (1 September to 28 February) and cold (1 March to 30 August)—as, following Tipping *et al.*, we assume water values may change, reflecting seasonal changes in expected inflows and load.<sup>57</sup> The Benmore grid exit point (GXP) reference price (BEN Price) was taken as the relevant reference price since it is closest to the majority of hydro storage. Figure 9.3 and Figure 9.4 below show the observed spot prices as a function of relative storage level RSL (split by season).

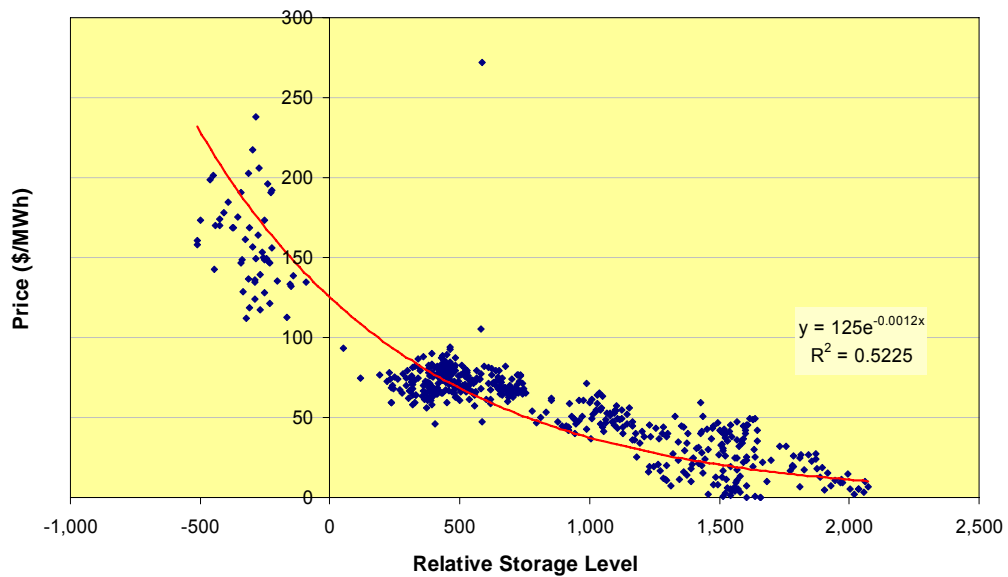
<sup>57</sup> Smaller breakdowns of the season were also considered, but due to lack of data post 1/6/2004, did not produce any more accurate results.

Figure 9.3: Observed spot prices as a function of storage vs RSL (Warm season)



Source: Castalia

Figure 9.4: Observed spot prices as a function of storage vs RSL (Cold season)



Source: Castalia

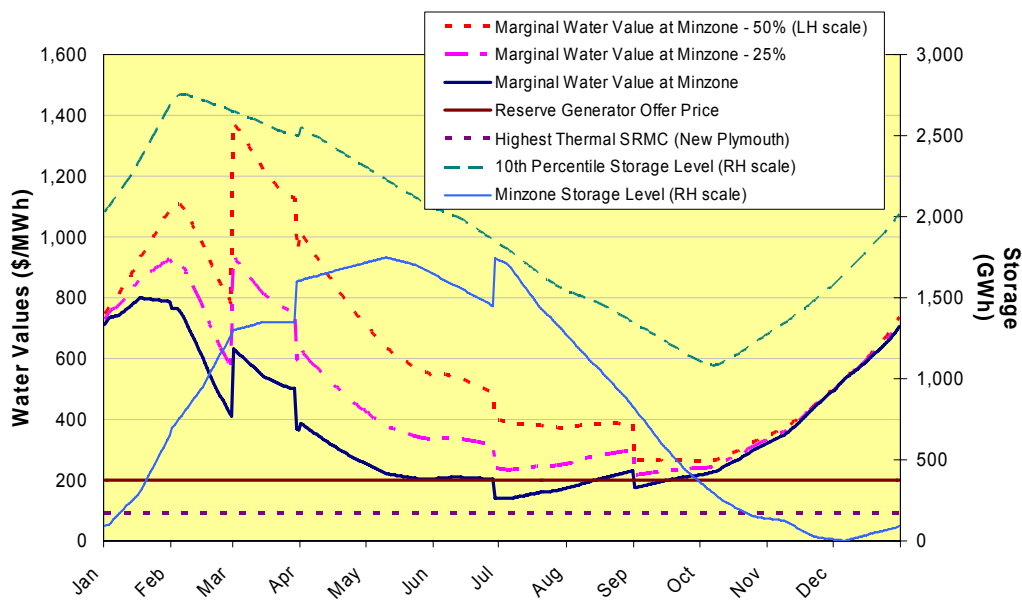
These charts show a very strong correlation between RSL and price. That is as RSL decreases, price tends to increase at an exponential rate.

Tipping *et al.* suggest that by using a best fit line to the observed prices as storage approaches the Minzone, it is possible to forecast what the spot price might be at lower storage levels, such as at the Minzone. The red curves in Figure 9.3 and Figure 9.4 show the water value curves derived from this approach.

These graphs show a reasonably strong, but not perfect, correlation between RSL and price. In particular, the spread of observed prices at a given RSL suggests other factors than just the RSL may be influencing price. This spread appears most pronounced at low RSL in the warm season. It is likely that the seasonal variation of water values may be greater than indicated by this analysis. We attempted a four season breakdown but insufficient data is available since the introduction of the Arrangements.

Despite the above limitations, we have derived an indicative market price at the Minzone and once the Minzone is breached from the above water value curves. Figure 9.5 shows the likely market price at and within the Minzone derived from this approach.

**Figure 9.5: Water values at and within the Minzone**



Source: Castalia

For details of the changes in Minzone in 1 April 2006 and 1 July 2006 see the Commission website ([www.electricitycommission.govt.nz](http://www.electricitycommission.govt.nz)).

The u-shaped dark blue line (water values at Minzone) suggests that water values are likely to be above the highest thermal power station SRMC (New Plymouth). This suggests that water values are likely to be sufficiently high to ensure all thermal generation is fully dispatched once the Minzone is breached. Hence, the assumed level of hydro storage conservation is likely to occur. Similarly, the dashed magenta and dotted red lines (water values at Minzone – 25 percent, and Minzone – 50 percent respectively) suggests water values will keep increasing once inside Minzone.

However, the results are less convincing in the areas where the Minzone is quite high relative to normal storage patterns (10<sup>th</sup> percentile storage level), e.g. May to August. Given the limitations of this approach, there is therefore a finite risk that not all thermal generation is fully dispatched within these months if the Minzone were breached.

One possible explanation of the apparently low water values within some of the Minzone in May to August, is that participants value the risk of non-supply differently to that implied in the Minzone derivation. For example, the Minzone is based on an absolute security standard (no forced rationing) rather than an optimal security standard. Also, the shape of the Minzone is based on a particular inflow sequence (1-in-60 year event), rather than the overall weighted probability of occurrence of a range of possible inflows. So, for example, if one particular inflow sequence had very low inflows during May to August, then the shape of the Minzone would be higher in these months than one based on overall weighted probability of occurrence of a range of possible inflows. This might result in lower water values at the Minzone in these months. This possible explanation is partly supported by the fact that the Minzone values in this area are closer to the 10<sup>th</sup> percentile storage levels than in other months.

Given the above possibility of incomplete thermal generation dispatch within the Minzone, consideration should be given to whether alternative Minzone operating regimes should be adopted. One such alternative regime would be to offer in the reserve energy at zero price whenever the Minzone is breached. However, the fact that the Minzone water value (blue line on graph) dips below the Whirinaki offer price (brown line on graph) suggests that at times (May to August) offering Whirinaki at less than \$200/MWh may not lead to as much hydro storage conservation as hoped, i.e. some thermal generation may be displaced as well as hydro generation. This is discussed further in Section 9.4.2.

### **9.2.2 Stakeholders' perceptions of the Minzone**

Most stakeholders interviewed as part of our information gathering either found the Minzone analysis useful for their own purposes, or considered that it was useful to other stakeholders, or both. For example, most large generators undertake their own detailed modelling, similar to the Commission's Minzone analysis. However, they may use the Minzone to cross check with their own analysis and also recognise that other less well-resourced stakeholders find the information useful.

Stakeholders generally agreed that the Minzone analysis, as currently published by the Commission, is a sensible way to operationalise the requirements of the Regime. However, many stakeholders also noted that a person not familiar with the industry and the Commission's approach may misunderstand the analysis. A perception of a high level of risk to security of supply may be created, even if the actual risk is very low.

Many stakeholders noted (and we agree) that this is mainly a presentation issue. For example, the Commission's publication of the Minzone currently uses a solid red line to represent the Minzone and a black line to represent the Emergency Zone. Individuals and organisations with little knowledge of the industry and the Arrangements may misconstrue (as arguably happened in 2006) storage dropping close to or below a red line as a sign of an imminent threat to security of supply. However, even if the Minzone is breached, there is only approximately a 1-in-60 (2 percent) chance that security of supply will not be maintained without the need for a conservation campaign. When the Emergency Zone is breached, that chance is increased to approximately 1-in-10 (10 percent). Simply changing the two colours denominating the Minzone and the Emergency Zone (to black and red respectively) may be sufficient to address such perception issues.

## **9.3 Procuring Reserve Energy**

In this section, we discuss and analyse the Commission's approach to procuring reserve energy, review stakeholder feedback on that approach, and recommend how the

procurement approach can be improved. By procuring reserve energy, we mean procuring an additional generating unit or demand response capability. The assumption is that if Commission foresees future security of supply problems, it would respond by procuring additional reserve energy.

### 9.3.1 Current approach to reserve energy procurement

The Commission currently assesses the need for reserve energy procurement by forecasting the Minzone two years ahead and checking whether the peak of the Minzone exceeds a particular trigger storage level.

The ‘peak of the Minzone’ refers to the highest level of storage required by the Minzone at any time in the year. In practice, the Minzone peak occurs at the beginning of winter—this is the point at which most storage is needed, to ensure the country can get through a dry winter without rationing.

If the security of supply problem were getting worse, more and more storage would be needed, and the required Minzone would keep rising. In principle, this could continue until the required Minzone actually exceeded 100 percent of available hydro storage. At this point, meeting security of supply requirements through additional hydro storage clearly becomes a physical impossibility, and the only solution would be to procure additional reserve energy.

In practice, the Commission sets a ‘trigger point’ for the Minzone peak that is lower than 100 percent of storage. The notion is to balance the risk of hydro spill from requiring the lakes to be kept very full, against the cost of additional reserve energy. The trigger storage level was initially set at 70 percent, based on indicative analysis, and is now calculated each time the needs assessment is carried out. The calculation compares the cost of reserve energy to the expected costs of spill (and resulting additional thermal fuel burn costs) under different Minzone scenarios. This is done to find the Minzone peak (expressed as a percentage of total storage) at which the two costs are equal.

If the projected Minzone has a higher peak than the trigger, the Commission will consider procuring additional reserve energy. The amount procured would in theory be sufficient to push the Minzone peak below the trigger storage level. The total amount that can be procured is also limited by the restriction set out in the Regime—no greater than 1,200 GWh for any four month period.

The Regime also states that:

*Generation plant that is contracted as reserve energy should primarily comprise plant with low fixed costs and high operating costs, including plant that would otherwise have been mothballed or retired, rather than baseload plant*

The Commission’s only reserve energy contract that fits the description of preferred reserve plant is Whirinaki.

The Act and the Regime require the Commission, in carrying out its security of supply responsibilities, to minimise any market distortion created. The measures taken by the Commission to limit distortion due to reserve energy procurement include:

- Delaying any procurement as long as possible
- Providing the market with as much information as possible to encourage the market to meet the 1-in-60 standard
- Limiting the total GWh that are procured, and

- Ring fencing the reserve energy procured and making the dispatch strategy for any reserve energy transparent.

### 9.3.2 Stakeholder feedback on current procurement approach

Many stakeholders noted that it was difficult to comment on reserve energy procurement because:

- No additional procurement has taken place since Whirinaki was handed to the Commission by the Government
- The Policy does not set out a specific trigger for procuring reserve energy, and
- The Policy does not set out how the actual procurement process will work if triggered.

Nevertheless, some possible improvements were proposed for consideration, including:

- Pre-consenting sites and tentatively procuring fuel contracts—we support this recommendation, as discussed in Section 6
- Procuring baseload, rather than only peaking plant—the various options considered in Section 6 that require full hedging of all energy needs move from a focus on peaking plant to an approach that would encompass baseload plant as well. We recommend implementing one of these options in the future if new evidence shows that New Zealand has a continuing and systemic security of supply problem
- Establishing an independent planning organisation to determine any reserve energy requirements (energy, location, timing) and run competitive tenders—we see no clear need for an additional body, and
- Considering the capacity problems (including the short-term loss of gas supply) as part of the procurement process, rather than focusing solely on the dry year energy problem—we agree that the hydro distribution Figure 3.1 should be augmented to allow for all energy-related risks.

### 9.3.3 Improving the procurement approach

There are two main areas that require improvement in our view:

- Setting a clear trigger for the procurement of additional reserve energy, and
- Defining a clear process for how procurement would actually take place.

Potential improvements for both areas are discussed separately below.

#### Setting a clear trigger for additional procurement

The trigger for considering the procurement of additional reserve energy should be based on the efficient level of security of supply discussed earlier.

The Minzone is the best available tool for monitoring security of supply over the next year or two but may not provide the most straight forward trigger for signalling the consideration of further procurement of reserve energy. The Minzone mechanism has been used to define a trigger that is effectively equivalent to an energy margin but has been constrained to model just the 1-in-60 physical standard of security of supply.

The earlier analysis sets out how assumptions regarding the marginal costs of un-served energy and of ways of providing additional energy adequacy (demand reduction contracts or reserve energy plants) lead to an optimal level of USE. To the precision with which we

know the shape of the combined probability distributions, we can determine the necessary energy margin.

Energy margins are an easy way for observers to assess the level of security of supply provided in generation expansion forecasts. We recommend that the trigger for additional procurement should be expressed in terms of a desired energy margin. As discussed earlier, the margin would need to be calculated in a way that accounts for transmission constraints, which may reduce the effective energy margin for particular regions. Our preliminary calculations indicate that the minimum desired energy margin would be between 12 and 18 percent. We recommend that the Commission should procure additional reserve energy when it becomes clear that the actual energy margin for any region will fall below the minimum desired level.

### **Defining the procurement process**

To give the market and other stakeholders certainty with respect to how additional reserve energy will be procured, a clear definition of the actual procurement process is required. As discussed in Section 4.3, either diesel- or gas-fired peaking plant (similar to Whirinaki), or contracted demand response are likely to be the most appropriate forms for any additional reserve energy required in the future. The Commission should therefore be able to define in advance the process and requirements for any future reserve energy tender. Separate requirements could be defined for demand response and reserve generation.

Pre-consenting sites for reserve generation would help reduce lead times for commissioning the plant. This would allow the Commission more waiting time to see if the market will respond, thereby reducing any distortion to the market. Pre-consenting will carry some costs because RMA procedures require any proposed project to be defined in quite some detail. The plant specification and consents may also need to be changed as technologies change.

#### **Box 9.1: Stakeholder feedback on recommendations regarding procurement**

All stakeholders providing comments on Castalia's recommendations regarding the trigger and process for procurement of reserve energy agreed that both the trigger and the process should be defined in the Policy and made public.

Source: Castalia

## **9.4 Dispatching Reserve Energy**

In this section, we discuss the Commission's current approach to dispatching reserve energy, stakeholder feedback on that approach and recommendations on how reserve energy dispatch can be improved.

### **9.4.1 Current approach to RE dispatch**

The default offer for reserve energy is currently 100 c/kWh. When storage is above the Minzone, but high sustained high spot prices are exhibited, reserve energy is offered at the higher of 20 c/kWh or the variable cost of each reserve energy option.<sup>58</sup> Should the Commission in future have multiple reserve energy options, variable costs for each option will depend on characteristics of that option (for example start-up times). Complex offers involving different offer prices under different circumstances may then be developed.

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<sup>58</sup> This is required by GPS Section 60

When storage falls below Minzone, and security of supply decreases below 1-in-60, reserve energy is dispatched in tranches (ranked in order of increasing costs—currently irrelevant since the Commission only has one option) to restore security of supply to a 1-in-60 standard. Security guidelines will also be developed to set the trigger security levels for the dispatch of each tranche of reserve energy. Likewise, as security of supply increases, tranches of reserve energy will be withdrawn when security of supply rises above the guideline level for that particular tranche.

#### **9.4.2 Impact of current reserve energy dispatch approach on thermal generation**

This section examines whether the Commission should offer Whirinaki at a price lower than its SRMC once the Minzone is breached. If Whirinaki were offered at a price below its SRMC, the effect would be to guarantee that the plant was run. The actual payment received by Whirinaki would be set by the offer price of the marginal generator.

We conclude that offering Whirinaki at below its SRMC in the Minzone is likely to displace some other thermal generation at certain times of year and may not actually sustain the level of hydro storage as much as anticipated.

This section also examines other methods of ensuring the expected level of hydro storage conservation is achieved once the Minzone is breached, as suggested by Morrison & Co. Morrison & Co conclude that most of these alternatives would result in greater market distortion than the current approach, the exception being a ‘comprehensive contracting approach’. However the comprehensive contracting approach could still increase the cost of operation of the Minzone and most of the benefits of this approach could be achieved by adopting an optimal Minzone standard. That is, an optimal Minzone standard is likely to lead to water values within the Minzone exceeding the SRMC of all thermal generators thus ensuring full dispatch of all thermal generators without the need for any intervention.

The Commission provides guidelines to Contact on how to offer Whirinaki into the market once the Minzone is breached in the “Whirinaki Power Station: Instructions to Offer Electricity” dated 2 November 2005. These state:

*“2 If storage is at or below the Minzone then, subject to 4,:*

*a. output from Whirinaki station will be offered at the RETP;<sup>59</sup>*

*b. the Electricity Commission will monitor the storage level published every day on COMIT hydro and the dispatch of Whirinaki station;*

*and*

*c. if the output offered from Whirinaki station is not making the contribution to security of supply expected, the Commission Board (“Board”) will investigate why cleared prices are lower than expected. The offer price will be reduced by the Electricity Commission if the Board’s investigation determines that a lower offer price will assist in achieving the 1 in 60 security of supply policy objective.”*

Given the possibility, as identified above, that in some seasons the cleared price may drop below 20 c/kWh within the Minzone, the Commission may be tempted to offer Whirinaki at less than this price as provided for in Section 2(c). of the “Instructions to

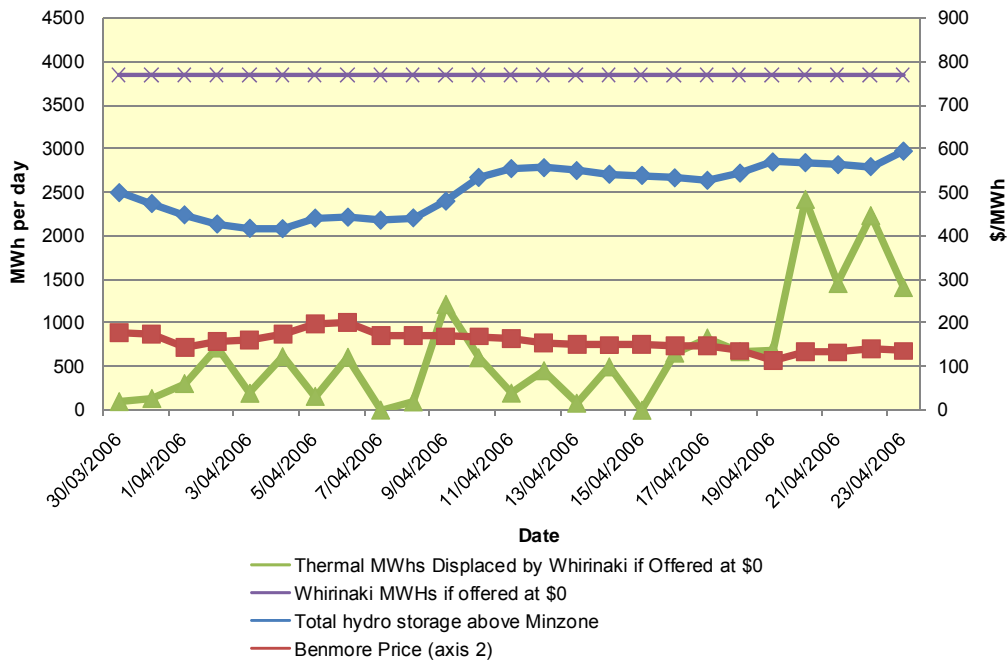
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<sup>59</sup> Reserve Energy Trigger Price. The RETP is \$200/MWh or the variable cost of the reserve energy contract, whichever is higher. Until the Commission publishes a variable cost, RETP is to be \$200/MWh. In the event that the Commission begins publishing a variable cost, the Commission will re-issue this instruction indicating where and when it will publish the variable cost.

Offer Electricity”. This raises the question of whether, in doing so, reserve energy may merely displace other thermal generation rather than conserve hydro storage.

To examine this question, we undertook a study of which generators were on the margin once the Minzone was approached. Since the Arrangements have been in place, hydro storage was closest to the Minzone during early 2006 (although the Minzone was not breached). The offers in this period were studied to determine how much thermal generation may have been displaced if Whirinaki were offered at sufficiently below the cleared price to just ensure it was fully dispatched.<sup>60</sup> The graph below shows the extent to which thermal generation would have been displaced if Whirinaki were offered at just sufficiently below the cleared price to ensure it was fully dispatched during early 2006.

**Figure 9.6: Impact of Whirinaki Being Offered below its SRMC**



Source: Castalia

Figure 9.6 demonstrates that other thermal generation would have been displaced by Whirinaki if it had been offered at below the cleared price. For every 100 MWh of additional energy dispatched from Whirinaki, approximately 16 MWh of other thermal generation would have been displaced. This is reasonably consistent with the calculated water values in this ‘cold’ season as noted in Section 9.2.1 above. It is also noted that the amount of thermal generation displaced may be greater than the above chart suggests as this calculation assumes that changing the Whirinaki offer strategy would not affect other parties offer strategy. Although this was a useful and necessary assumption for this exercise, it is unlikely to be the case in reality, and revised generator offer strategies could result in even greater displacement of other thermal generation if Whirinaki was offered below its SRMC.

<sup>60</sup> The Commission can choose to offer Whirinaki at any price. For the purposes of this study we assumed Whirinaki had perfect foreknowledge and could offer at a price just sufficiently low to achieve full dispatch without disrupting other generators offer patterns.

However, the Minzone was not actually breached in the period under study and it is likely that water values would be higher once the Minzone was breached and hence less thermal generation would have been displaced if the Minzone were actually breached.

The above modelling also raises the question of whether there might be better ways to manage the dispatch of reserve energy within the Minzone to both ensure the desired level of thermal generation is achieved and avoid this potential problem of reserve energy merely displacing market generation at some times. Morrison & Co suggest a number of alternatives to deal with these short run issues:

- Option 1—Pre-contracting for minimum hydro storage
- Option 2—Comprehensive pre-contracting for hydro storage and equivalent thermal capacity
- Option 3 – Control and Command in the Minzone
- Option 4 – Just in time contracting for non-hydro generation, and
- Option 5 – Just in time contracting to maintain hydro storage.

We accept that each option would achieve a high degree of certainty that the expected level of thermal generation within the Minzone is achieved. However, as noted by Morrison & Co, this is at the expense of various levels of market distortion or gaming.

Option 3 involves a high level of interference in the market and would be highly distorting of market price signals. Options 4 and 5 would run a high risk of being at the mercy of the generators offering the storage and encourage gaming.<sup>61</sup> Option 1 is likely to be expensive as it restricts the contracting regime to a limited set of parties, and would introduce market distortions, albeit less than options 3, 4 or 5.

Morrison & Co favours option 2, considering it likely to be least expensive and most likely to align with generators own strategies to maximise profit and manage their own dry year risk. However, this raises the question of how the problem arises of water values within the Minzone being too low to achieve the desired level of thermal generation. It could arise either because the Minzone does not perfectly correlate to generators' own perceptions of dry year risk, or due to the 1-in-60 standard being uneconomically high.

As noted in Section 9.2.1, the shape of the current Minzone may not perfectly reflect an optimal security standard,<sup>62</sup> and thus participant's water values may, in some months, be close to the SRMC of some thermal generators. To the extent that the Minzone does not perfectly reflect an optimal security standard, even option 2 will increase the costs of operation of the reserve energy arrangements. Conversely, if the Minzone were defined based on an optimal security standard, then either water values at the Minzone would be such that they did ensure the assumed level of thermal generation within the Minzone, or the costs of any intervention to ensure this was achieved, would be minimal.

#### **9.4.3 Stakeholder feedback on current dispatch approach**

Stakeholder views on dispatch strategy for reserve energy can, for the most part, be grouped into two schools of thought. One opinion is that reserve energy should have a

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<sup>61</sup> The Commission's Security Advisory Group did examine options 4 and 5 in some detail in 2005 and concluded that they would be complex to implement and have a reasonably high risk of market disruption.

<sup>62</sup> As noted in Section 9.2.1, the Minzone shape is much closer to the 10<sup>th</sup> percentile level of historic storage in May to August than in other months. This appears to be driven by a particular inflow sequence for those months. An optimal security standard is more likely to reflect the average risk of loss of supply (rather than be dominated by one rare event), and thus lead to a slightly lower Minzone in this area and correspondingly higher water values.

purely physical trigger (such as when storage enters the Minzone), since the plant's purpose is to manage dry year risk. This role could also be expanded to manage other contingencies, with reserve energy being dispatched when Grid Emergencies are declared by the System Operator.

The other opinion is that, while reserve energy is procured to manage dry year risk, once procurement actually takes place, the market should help determine what the optimal use for this new resource should be. Reserve energy should therefore be used as any other commercial asset in the market and be offered into the market at its SRMC.

#### 9.4.4 Recommended improvements to dispatch of reserve energy

At present Whirinaki is dispatched at 20 c/kWh or at the variable cost of the fuel if that is higher. There appears to be no material 'ring fencing' in operation and from an economic perspective, it would be better simply to dispatch the plant at SRMC.

With future diesel-fired open cycle gas turbine plants, the same should apply. There may be a supposition that a higher dispatch trigger would reduce the distortion to investment but the higher trigger is difficult to commit to convincingly. When prices are very high, there will be considerable pressure to use all available plant.

#### **Box 9.2: Stakeholder feedback on recommendations regarding dispatch**

Most stakeholders supported Castalia's recommendation that reserve energy, including Whirinaki, should be dispatched at SRMC. MEUG also suggested that, if Whirinaki were to be dispatched at SRMC, there appears to be no reason why the plant should continue to be in public ownership—any commercial owner would also dispatch the plant at SRMC. MEUG therefore suggested that Whirinaki be sold. This suggestion was discussed at the public hearing and was supported by most stakeholders, including consumer representatives (Grey Power and Ms. Melhuish). In our view, this suggestion warrants further consideration by the Commission and the Government, depending on whether our recommendations regarding the dispatch of reserve energy are accepted.

Source: Castalia

## 9.5 Providing the Market with Information

The Policy provides for a “*strong focus on providing information and analysis of supply and demand and security of supply, in order to maximise the opportunity for market participants to manage security of supply risks.*”. Below we discuss the information currently provided by the Commission, stakeholder views on that, and recommendations on how the information can be improved.

### 9.5.1 Information currently provided

The Policy provides for the publication of:

- Short-term assessments of the security margin for two, four and six months ahead
- A two-year forecast of the 1-in-60 Minzone, and
- A long-term (10 year) forecast of the winter energy margin.

Currently, only the two-year and the long term forecasts are published, though work is underway on the short-term security assessments. The Commission also publishes and updates a 'risk meter' pie chart on its website. The intent of the publications is to provide participants with relevant information and encourage them to manage security of supply

by making timely investments and thus avoiding the need for reserve energy procurement and dispatch.

The underlying analysis for the publications relies, to a large degree, on information that is voluntarily made available by market participants (such as information on plant availability, fuel stockpiles levels and upcoming generation build). The information is currently not adjusted for any possible bias of the parties providing it.

### **9.5.2 Stakeholder views**

Most stakeholders consider the information published by the Commission is helpful, but could be improved in several ways. For example, stakeholders do not understand how the Minzone is actually derived and many noted that they would welcome more clarity about the assumptions and modelling methods behind the Minzone. Stakeholders with modelling capabilities (generators and retailers) want to be able to reproduce the Minzone for closer cross-checking with other modelling carried out internally. Stakeholders without the modelling capabilities (such as major energy users) want some reassurance that the assumptions behind the Minzone are realistic. Stakeholders without technical knowledge (mainly consumer groups) would also like to see information that is simple and easy for consumers to understand.

Most stakeholders also commented on the Commission's use of voluntarily-provided information. Although some suggested that a mandatory information provision regime may be more appropriate, most (including MEUG) agreed that the current arrangement appears to be working well.

### **9.5.3 Analysis and recommendations**

While it might seem that a compulsory framework for information gathering may be more robust, introducing such a framework would be costly and it is not apparent that substantial incremental benefits would result (especially given difficulties in enforcing some aspects of information provision). The Commission, as well as most stakeholders, is comfortable that the information provided to date has been accurate and sufficient for the Commission's purposes. It is therefore appropriate to retain the voluntary approach to information provision. This decision should be revisited from time to time, especially if the quality of information provided appears to deteriorate.

We also agree that more clarity around the Minzone assumptions and calculations would be helpful to stakeholders. However, some of the information that the analysis is based on is commercially sensitive and has been provided to the Commission in good faith and in confidence. It is important to ensure that this information remains confidential. Nevertheless, to the extent possible, the Commission should look to improve the transparency and clarity of the Minzone analysis.

Discussion with stakeholders also suggested that perceptions of actual risk to security of supply at any point in time could be assisted by making it more obvious that the Minzone boundary records where the risk of some demand restraint reaches 1-in-60, not where conservation campaigns are required. Given the differing preferences of different stakeholders with respect to the level of detail they would like to see disclosed, the Commission could also specifically target some publications for lay-people and others for market participants.

**Box 9.3: Stakeholder comments on recommendations for information provision**

All stakeholders supported Castalia’s view that the Commission needs to improve how it provides information to the market regarding the standard for and actual level of security of supply. Stakeholders also generally agreed that the various information provided by the Commission needs to be tailored to the audience for that particular piece of information.

Following our draft recommendation that a voluntary information provision regime be retained, all but two submitters (Grey Power and Ms. Melhuish) agreed with this recommendation. Grey Power did not comment on the issue of whether information provision to the Commission should remain voluntary, while Ms. Melhuish submitted that compulsory provision was more appropriate because there is no incentive on market participants to provide accurate information.

Source: Castalia

## 9.6 Managing Conflicts of Interest

The Regime requires the Commission to put in place and publish protocols to manage conflicts of interest resulting from its role as a regulator and a market participant. The Commission’s protocols are set out in Section 16 of the Policy:

*The Commission’s conflict of interest will be addressed by the publication (and transparent compliance with) clearly articulated security of supply policies. These policies will provide for:*

- *Key details of Reserve Energy contracts to be published including how and when the contracts will be triggered relative to spot prices and published security guidelines.*
- *Reserve Energy to be offered into the market along the same lines as normal supply and interruptible load.*
- *Reserve Energy contracts to be settled by the Clearing Manager.*
- *Ex-post publication of reserve energy triggers, offers and use.*
- *Investigations of any compliance issues relating to reserve energy contracts directly by the Rulings Panel rather than the Board...*

Stakeholder feedback on conflicts of interest protocols indicates that most stakeholders are comfortable that the conflicts arising from the Commission’s role as a regulator and market participant have been managed well by the current Policy. However, a number of stakeholders noted that, in their view, the biggest conflict of interest arises from the Commission’s lack of full independence from the Government.

We agree that the Policy provides a good framework for managing conflicts of interest related to the Commission’s role as regulator and market participant. Therefore, we do not recommend any changes to this part of the framework. The Commission’s degree of independence from Government is defined in the Electricity Act and is outside the scope of this Review.

## 9.7 Managing Security of Supply Beyond the Standard

We note that the Commission has a workstream (dry year emergency policy, including an interim Emergency Response Plan) under way to ensure that, in a worse than 1-in-60 dry year, security of supply is maintained. The Commission is also working on how forced rationing can be implemented in a least-cost way, should it ever be required.

Given the limited amount of time the Commission has had to undertake this work and the fact that the workstream is not yet complete, we consider that it would be premature

to assess the dry year emergency policy at this time. However, we recommend that the Commission maintain its focus on least cost forced rationing, should it be required.

## **9.8 Summary of Recommended Improvements to the Policy**

The sections above have addressed questions in respect of the workings of the existing Policy. Below we summarise our recommendations.

### **9.8.1 Procuring reserve energy**

There are two main aspects of the procurement approach that require improvement:

- Setting a clear trigger for the procurement of additional reserve energy, and
- Defining a clear process for how procurement would actually take place.

With respect to setting a clear trigger, we recommend that the trigger for additional procurement should be expressed in terms of a desired energy margin. Our preliminary calculations indicate that the minimum desired energy margin would be between 11 and 17 percent. We recommend that the Commission should procure additional reserve energy when it becomes clear that the actual energy margin will fall below the minimum desired level.

With respect to defining a clear process, we recommend that the Commission should define in advance the process and requirements for any future reserve energy tender. This should be relatively straight forward because it is clear that the most appropriate forms for any additional reserve energy required in the future are likely to be either:

- Diesel- or gas-fired peaking plant (similar to Whirinaki), or
- Contracted demand response.

Defining the likely forms of reserve energy to be procured would also help facilitate a pre-consenting process by setting out detailed specifications for reserve generation (such as plant type and location). Pre-consenting sites for reserve generation would help reduce lead times for commissioning the plant, which would allow the Commission more waiting time to see if the market will respond, thereby reducing any distortion to the market.

### **9.8.2 Dispatching reserve energy**

At present, Whirinaki is dispatched at 20 c/kWh or at the variable cost of the fuel if that is higher. There appears to be no material 'ring fencing' in operation and, from an economic perspective, it would be better simply to dispatch the plant at SRMC. With future sources of reserve energy, the same approach should apply.

There is some risk that dispatching Whirinaki at the Minzone boundary when spot prices are below 20 c/kWh would displace some thermal generation and hence not conserve water, but we cannot resolve this issue without some experience of actual Minzone prices.

### **9.8.3 Providing information**

While it might seem that a compulsory framework for information gathering may be more robust, given that the Commission is generally satisfied with the quality of information provided so far, it is appropriate to retain the voluntary approach. This decision should be revisited from time to time, especially if the quality of information provided appears to deteriorate.

Also, more clarity should be provided to stakeholders around the Minzone assumptions and calculations. For example, perceptions of actual risk to security of supply at any

point in time could be better managed by making it more obvious that the Minzone boundary records where the risk of some demand restraint reaches 1-in-60, not where conservation campaigns are required. However, commercially sensitive information provided to the Commission in good faith and in confidence should remain confidential. The Commission could also specifically target some publications for lay-people and others for market participants, given the differing preferences with respect to the level of detail stakeholders would like to see disclosed.

# Appendix A: International Approaches to Ensuring Security of Supply

To help consider the security of supply issues for New Zealand we sought to examine the experience and approaches of other countries with similar issues. In this appendix we set out the results of our international review.

## A.1 Selecting Comparator Countries

In our search we looked for countries with similar physical system characteristics to that of New Zealand. The two main physical characteristics that distinguish the New Zealand system from most other countries are:

- **Geographic Isolation**—New Zealand has no interconnection with other countries and cannot purchase power from other countries to overcome energy shortfalls, and
- **Substantial Exposure to Fuel Risk**—A large part (56 percent on average) of New Zealand’s generation comes from hydro sources. Our hydro stations have limited storage capacity (approximately 10 percent of annual demand). In dry periods inflows can be reduced by around 20 percent, requiring substantial thermal backup.

These characteristics were used as criteria when selecting potential comparators. However, very few countries combine both these factors, so we included countries that have either one or the other characteristic. The comparators selected were Iceland, Japan, Norway, Brazil and Chile.

Of course, it would be ideal if comparator countries also had similar market structure to that of New Zealand. However, this would narrow the pool of comparators to one country—Norway. While Iceland also has a newly established wholesale electricity market for contracts, it does not have a spot market. We also added the United Kingdom as a comparator that is an island nation with a well-developed electricity market and a recognised security of supply issue during a cold winter.

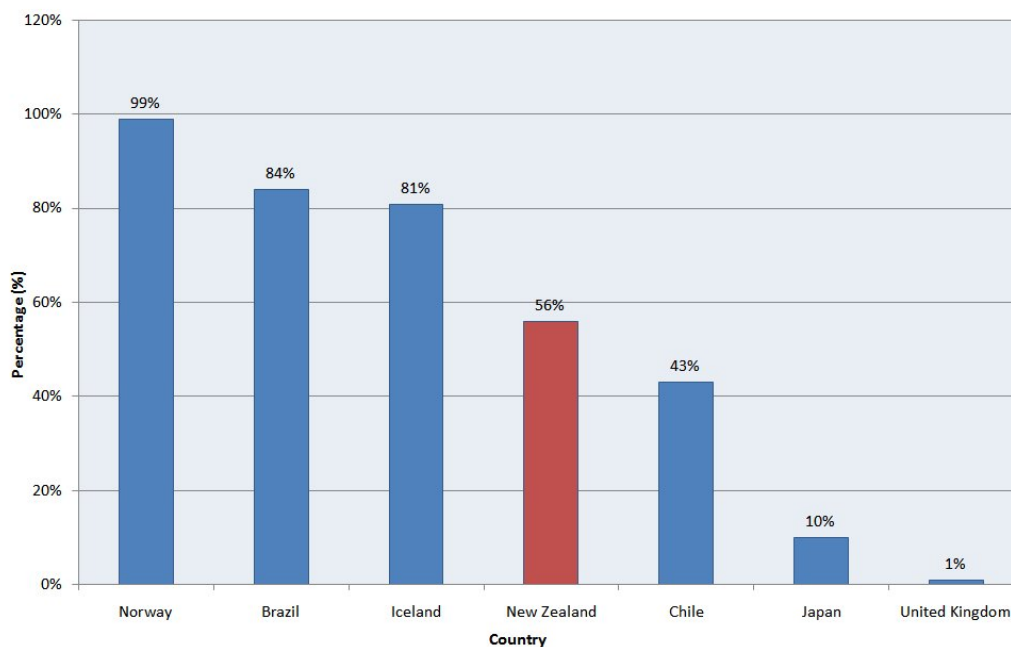
There is no single model from which we can learn. Rather, it is a question of gleaning relevant lessons from a range of cases. Table 9.1 summarises the key characteristics of comparator countries.

**Table 9.1: Characteristics of Comparator Countries' Electricity Sectors**

Country	Substantially exposed to fuel risk?	Has no or very limited interconnection to other countries?	Percentage of Hydro Generation
Iceland	Yes (hydro)	Yes	81%
Japan	Yes (fossil fuel imports)	Yes	10%
Norway	Yes (hydro)	No	99%
Brazil	Yes (hydro)	No	84%
Chile	Yes (hydro)	No	43%
United Kingdom	No	Yes	1%

Source: Castalia

**Figure 9.7: Percentage of Hydro Generation in Comparator Countries**



Source: Castalia

## A.2 Approaches Adopted by Comparator Countries

In the subsections below, for each comparator country, we summarise the key characteristics of the electricity sector, the security of supply policies and responses and relevance to circumstances in New Zealand.

### **A.2.1 Iceland**

Iceland is a comparator country that shares most similarities with New Zealand. Iceland has installed generation capacity of 1507 MW. Hydro generation supplies 82.7 percent of Iceland's electrical energy, while geothermal generation supplies the remainder. There are some diesel generators which represent 7.9 percent of installed capacity, but are used almost exclusively for back-up purposes. Iceland has an abundance of available energy sources, since both hydro and geothermal electricity generation potential in Iceland is largely unutilised.

Iceland introduced a wholesale market in 2006. Unlike the New Zealand market, where energy is traded in half-hour intervals, in the Icelandic market wholesale contracts of varying durations are traded. The majority of generation, as well as the grid owner and system operator are still owned by the Government, which has dampened the development of competition.

The main driver for electricity demand in Iceland is industry and, in particular, aluminium smelting, which uses almost 50 percent of electricity. This means that demand growth is fairly predictable and occurs in large steps, which allows contracts to be signed for underwriting new generation capacity.

There are two types of energy that can be sold in the market. Primary (or firm) energy is energy that can be produced despite natural fluctuations in water flows. This energy is firm to a 1-in-100 year standard. Secondary energy is excess energy during summer and winter months when hydrology is favourable. It is sold at lower price under a condition that it can be cut back. This means that customers can make a trade-off with respect to the level of security of supply they receive.

Iceland does not have an explicit security of supply regime. Rather, as all trade in energy is through contracts, legislation simply requires suppliers to provide the electricity necessary to meet contract obligations.

### **A.2.2 Japan**

Japan has 243,000 MW of installed generation capacity. Thermal generation accounts for 61 percent of energy supplied, followed by nuclear at 28 percent and hydro generation at 10 percent. One unusual feature of the generation mix is a large number of oil fired plants. Japan has no wholesale market. Instead, its electricity industry is dominated by ten privately owned vertically integrated companies that are regional monopolies. Reforms are currently underway to liberalise the electricity industry in Japan.

The vertically integrated utilities have a legal obligation to supply electricity. To ensure they meet this obligation, the utilities produce demand and supply forecasts, which are then reviewed by the Agency of Natural Resources and Energy (ANRE). Although ANRE does not specify the required reserve margin, the utility companies generally target a reserve margin of between eight and ten percent.

The main security of supply issue in Japan is the country's reliance on imported fossil fuels for electricity generation. This issue was highlighted by the Oil Shocks in the 1970's. Since then, Japan has moved towards reducing its reliance on imported fuels and encouraged use of nuclear energy. Nevertheless, Japan still greatly relies on imported fossil fuels. In response to the 1973 Oil Shock, the Japanese Government enacted the Oil Stock Pile Law in 1975. Under this law, it is mandatory for oil importers and traders (i.e. suppliers of fuel) to maintain 70 day stockpiles of oil and LPG. The Government of Japan also maintains a 90 day stockpile of net oil imports.

### **A.2.3 United Kingdom**

United Kingdom (UK) has installed generation capacity of 74,000 MW. Thermal generation accounts for 74 percent of energy supplied, followed by nuclear energy at 23 percent. Hydro generation accounts for only one percent of energy supplied. The UK is therefore largely reliant on fossil fuels (coal, gas and oil). Historically, the fuel requirements for thermal plant have been provided for domestically. However, it is predicted that by 2015 the UK will become a major importer of gas and oil.

The electricity industry in the UK is fully privatised and operates a wholesale market. Although there are three interconnections with other countries (France, Northern Island and Isle of Man), these are very small when compared to domestic installed generation capacity (2000 MW, 250 MW and 40 MW respectively).

Due to the country's fuel self sufficiency and historic overinvestment, security of supply has not been an issue in the UK to date. Since its start in 1990, the market has maintained a reserve margin of around 20 percent. However, security of supply is increasingly becoming a concern with many coal plants set to be shut down as they are not able to meet new clean air regulations. The UK government is currently developing policy responses to this challenge.

The UK system operator (National Grid), consulting and working in good faith with the energy regulator (OFGEM) monitors security of supply over upcoming winter periods and provides information to the market in order to facilitate its efficient operation. The severe winter problem in the UK is similar to that of the dry year problem in New Zealand. The main difference is that, rather than reducing energy supply over an extended period of time (as is the case with a dry year), a cold winter increases short term demand peaks. Other than providing additional information to market participants, the UK framework does not seek to interfere with the market, allowing it to respond to the information available. One of the reasons this approach may involve less risk in the UK (as opposed to New Zealand) is that the UK has a large number of mothballed plants that can quickly be brought back online.

### **A.2.4 Norway**

Norway is often quoted as a good comparator to New Zealand, however the differences between Norway and New Zealand are significant. Norway has installed generation capacity of 28,000 MW. Hydro generation supplies 99 percent of Norway's electrical energy. Norway participates in Nord Pool, a wholesale market that includes Norway, Sweden, Denmark and Finland. This means that Norway has extensive interconnections with other countries. After a long period of having excess generation capacity, Norway now faces a lack of generation capacity. Since 1992, investment in new generation capacity has been minimal while demand has grown steadily. This means that Norway faces a prospect of becoming a net importer of electricity.

Norway experienced a dry year combined with a cold winter in 2002. This was seen as a one in a hundred event. However, market response ensured that no load shedding occurred. There was substantial demand response, since most of the demand in Norway is exposed to the wholesale price, and electricity imports ensured that any demand in excess of domestic generation was met.

Norway has so far relied on energy imports from other countries and demand response to provide security of supply. Most of the customers, including residential customers, are on contracts that expose them to the spot price. During the 2002 dry year, these mechanisms ensured there was no involuntary load shedding. However, ensuring security of supply in such a way came at a significant cost (high local spot prices and high prices

for energy imports from Nord Pool). Following the events in 2002, a Norwegian Security of Supply White Paper was issued in December 2003 and discussed in Parliament in May 2004. The conclusion of the White Paper and discussions in Parliament was to make the grid owner and system operator (Statnett) responsible for ensuring security of supply. Statnett's obligation includes not only ensuring momentary balance in the system, but also ensuring that supply meets demand in the longer term, even during dry years.

It was left up to Statnett to decide what mechanisms it would use to achieve security of supply. In January 2007, Statnett signed a contract to purchase a total of 300 MW of gas fired generation that will serve as reserve energy.

#### **A.2.5 Chile**

Chile has installed generation capacity of 10,700 MW. Hydro generation supplies 43 percent of Chile's electrical energy, while the rest is supplied by thermal power plants, mostly natural gas fired and some coal fired. The Chilean power market has both a spot market and market for futures contracts. The futures contracts are either regulated price contracts for sale of electricity to regulated customers, or contracts to free customers, which are customers with a load bigger than 2 MW.

The Chilean power system suffered worst drought in previous forty years in 1998 and 1999. The market price setting mechanisms failed to anticipate this event, which led to early use of available water. Political intervention further aggravated the situation by ordering more water to be used to keep prices down. The electricity industry did not have a set response plan for these situations. The final result involved sporadic blackouts that lasted from November 1998 to April 1999.

Chile can expect to have a significant drought every 20 years. Another threat to security of supply for Chile is its reliance on natural gas from Argentina for gas-fired power plants. In 2004, Argentina reduced gas deliveries to Chile by 15 percent, which resulted in increased use of diesel fired generation in Chile.

As a result of the drought in 1998 and 1999, a security of supply response regime was implemented. This regime specifies that the generators have to pay fines and compensate customers who are affected by blackouts. Also, should rationing be required, supply to all customers has to be reduced proportionally, in accordance with a plan for rolling blackouts. Overall, this response regime provides incentives to minimise load shedding, but controlled load shedding is still the main mechanism that will be used during an energy crisis. Chile is also looking at diversifying its sources of natural gas supply.

#### **A.2.6 Brazil**

Brazil has installed generation capacity of 86,500 MW. It relies heavily on hydro generation, which accounts for 84 percent of installed capacity. Minor contributions are also provided by natural gas and oil fired generation, as well as nuclear. Brazil's power market works on an auction principle for both existing and new power plants. In these auctions, the generators which chose to participate, bid on contracts to sell power to the distributors, which have to participate in the auction. All auctions have a reserve price for power—a permitted maximum price. For new power plants, the Government of Brazil chooses the power projects it wants to auction and offers a long-term (30 years) concession contract that generators can bid on. Brazil currently has excess generation capacity. While this excess capacity is expected to run out around 2010, the Government's main concern has been to secure lower priced electricity from new power plants.

The auction system for new generation capacity means that procurement of new generation is centrally planned by the Government to ensure security of supply. There is no explicit framework on how the government decide when and how much new generation should be built.

### **A.3 New Zealand’s Unique Energy Security Problem**

Our review of international comparators shows that, of all developed countries with significant reliance on hydro generation, only Iceland can be compared to New Zealand in terms of geographical isolation. Most other hydro-reliant countries have significant interconnection with other countries in the region, thereby managing their exposure to dry years.

Furthermore, as demonstrated in Table 9.2 below, in addition to interconnection, most hydro-reliant countries have significant reservoir storage (29 percent to 147 percent of annual consumption) to help manage dry year risk. New Zealand’s hydro-storage, on the other hand, is only equivalent to approximately 10 percent of annual consumption.

**Table 9.2: Hydro Storage in Comparator Countries**

<b>Country</b>	Hydro storage as % of annual consumption
New Zealand	10%
Brazil	85%
Iceland	29%
Norway	147%

Source: Castalia

The particular characteristics of the New Zealand electricity system therefore create a problem of security of energy (rather than peak capacity) that is unique.

### **A.4 Conclusion**

Our international review shows wide variation of approaches adopted by different countries to ensure security of supply. The United Kingdom fully relies on the market to deliver, Iceland and Japan place obligations to supply on market participants, while Norway places that obligation on the system operator. Brazil seeks to centrally control generation investment, while Chile exposes customers to a significant risk of outages. Table 9.3 below summarises the different approaches adopted by international comparators. In addition, the table summarises the approach used in the United States.

**Table 9.3: Summary of Approaches to Ensuring Security of Supply**

Country	Approach to ensuring security of supply
Iceland	All energy traded through contracts. Legislation requires suppliers to provide the electricity necessary to meet contract obligations. Demand growth driven largely by industrial investment, making it easier to underwrite new generation investment
Japan	Obligation to supply placed on vertically integrated utilities, in exchange for granting regional monopolies. The companies generally aim for a reserve margin of 8 to 10 percent
United Kingdom	Provide market with information and rely on market to deliver optimal security. Monitor whether a 1-in-50 cold winter peak demand can be met. A 20 percent reserve capacity margin is used as a monitoring benchmark by the system operator
Norway	A similar mechanism to New Zealand, with the system operator Statnett procuring reserve energy (or taking any other action as needed) to ensure security of supply. The reserve energy plant (gas turbines) can be dispatched when the probability of shortages reaches 50 percent in the relevant region and may be offered below SRMC. Statnett operates with a regulated revenue cap intended to absorb profits and losses from the operation of reserve energy plant
Brazil	Government ensures security of supply by centrally planning and auctioning off any new generation projects. No clear framework for deciding when and how much new generation is required
Chile	Impose financial penalties on generators for any non-supply, but accept that some forced rationing may be required from time to time
United States	Loss of Load Expectation (LOLE) is set by the North American Electric Reliability Council, or a regional regulator. The LOLE is usually in the order of 1 day of non-supply in 10 years. Each region or market then decides how it will meet the LOLE requirement. Often, a minimum reserve margin is used—PJM aims for a minimum reserve margin of 15 percent, while Load Serving Entities in New York aim for 18 percent

Source: Castalia

Overall, there are no clearly superior approaches to inspire the analysis for New Zealand.

## Appendix B: Interventions for Ensuring Adequacy

### B.1 Capacity mechanisms

#### B.1.1 ICAP

Installed capacity (ICAP) mechanisms are in use in several eastern US markets (PJM, New York and New England) but appear to be constantly under review.

Obligations are imposed on each purchaser (known as a load serving entity or LSE) to procure installed capacity ‘tickets’ (which may include own generation) in proportion to their contribution to peak load.

Purchasers must demonstrate that they have sufficient tickets to meet their obligations before the start of the month-long obligation period, and are penalised for failure to do so.

The capacity of ICAP resources is determined by the system operator based on historical plant operational data,<sup>63</sup> and audited for compliance with specified requirements. Generators with registered installed capacity must make tickets available for sale, either through bilateral contracts or the centralised market. They must also make their plant available to the spot market (by offering it into the day ahead market) unless they have suffered a forced outage or are on a scheduled outage agreed with the system operator.

The shortcomings of ICAP regimes in terms of delivering capacity requirements are:

- Administrative complexity and cost (load forecasting, auditing and verification of ICAP resources and their availability, monitoring of LSE obligations, operating monthly auctions)
- Short term nature of the arrangement, which it is considered may lead to inefficient investment decisions, particularly with regard to size and timing
- High transaction costs for market participants to meet obligations, and
- Difficulty dealing with load shifting between load serving entities.

Altering the ICAP type approach to have an energy adequacy basis produces a contract to make energy available to the market over a period of time. This bears strong similarities to the compulsory dry year insurance regime discussed later in this appendix.

#### B.1.2 ACAP

An available capacity mechanism is in use in the PJM West jurisdiction of the United States. ACAP markets are operated in a similar manner to ICAP markets. Obligations are imposed on each purchaser to procure capacity ‘tickets’ in proportion to their contribution to peak load, and generators must make tickets available for sale.

The primary difference between ICAP and ACAP is the nature of the performance obligation, and the method by which the ‘ticket’ value is determined. Whereas ICAP capacity value is based on historical outage data and ICAP resources are only required to be available for a specified percentage of months for which tickets are sold, ACAP requires that capacity be fully available at all periods for which ACAP ‘tickets’ are sold. In the event of an unscheduled plant outage, a supplier with ACAP responsibilities must provide a substitute resource or face penalties for failing to do so.

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<sup>63</sup> ICAP capacity value is stated in terms of ‘unforced capacity’, which equals maximum generating capacity x (1- probability of forced outage).

The shortcomings of the ACAP approach are similar to those listed above for ICAP.

### **B.1.3 CRAM**

The Centralised Resource Adequacy Mechanism (CRAM) is a central procurement version of ICAP which has been specifically developed to replace ICAP-type mechanisms in some eastern US markets. The CRAM mechanism takes a longer term view than ICAP/ACAP, with capacity requirements and loads forecast and tickets procured some years in advance.

Whereas ICAP/ACAP impose obligations on purchasers to procure capacity rights commensurate with their own forecast load, CRAM centralises this process by procuring rights on behalf of purchasers and passing the costs through to them. Procurement is through a central auction which discovers a single clearing price, and avoids the need for individual purchasers to forecast load or individually acquire capacity. Costs are allocated evenly across all purchasers in the year covered by the commitment, and providers of CRAM resources are paid in the same year.

Resources offered into the auction may include existing or planned generation, load management, and transmission upgrades. Penalties apply for failure by providers to deliver committed resources in the year for which it is committed.

Relative to the ICAP/ACAP mechanisms, CRAM is considered less onerous for purchasers, and has the benefits that it takes a longer term view and does not depend on allocating load to individual retailers. However, it is suggested that there may not be as strong incentives for least cost procurement as under ICAP (due to the flat cost allocation).

As with ICAP/ACAP, the CRAM approach has an equivalent approach focused on energy rather than capacity adequacy, being the centrally procured dry year insurance contracts discussed later in this appendix.

### **B.1.4 Price Adders**

A price adder was used in the UK pool model before it was replaced by the New Electricity Trading Arrangements (NETA). A price adder is an additional payment to generators that offer to generate or are dispatched in a particular trading period, i.e. a payment for provision of real time capacity.

The rationale for these payments is to 'correct' spot prices when they are considered to undervalue reliability, which may be during all periods, or only during periods when a shortfall is considered likely. As with other capacity mechanisms price adders provide an additional revenue stream for generators which may replace any 'missing money' from the energy-only markets, but unlike the other mechanisms they do not provide a high degree of assurance of future adequacy. Payments are funded through an uplift charge.

The shortcomings of price adder mechanisms in terms of delivering capacity requirements are:

- They exacerbate spot price volatility
- They add little value to prices other than paying plant that is offered but not dispatched – the adder is intended to 'correct' spot prices but the payments will actually be somewhat arbitrary
- There is no guarantee that the mechanism will deliver any additional capacity investment

- Generators can exercise market power by withholding capacity in order to increase the loss of load probability and therefore the payment received, and
- If there is no ‘missing money’, then generators will over-recover on investments, resulting in a wealth transfer from consumers to producers.

The advantages of this type of mechanism are relative ease of implementation, little or no compliance monitoring, no need for a penalty regime, and no additional transaction costs imposed on market participants.

A capacity-based price adder (i.e. one that is linked to specific trading periods) would not address energy adequacy issues, particularly where there is significant energy-constrained hydro generation plant, unless it was amended to have a seasonal energy rather than trading period peak demand basis.

## **B.2 Energy Mechanisms**

### **B.2.1 Dry year insurance schemes**

A number of dry year insurance variants have been proposed to address New Zealand’s potential energy inadequacy issues. These mechanisms aim not only to deliver efficient investment in enough capacity to meet dry year requirements, but to finance that capacity in a way that does not result in extremely high price spikes during dry years. The schemes range from fully centrally procured, to fully decentralised.

#### **(i) Centrally procured reliability guarantee contracts (Hansen)**

The Commission procures option ‘insurance contracts’ from all generators that can physically supply in a dry year, and allocates the options and associated costs to all consumers.<sup>64</sup> Options are only exercised when spot prices are higher than the (single) trigger price, at which time the spot market becomes an inter-generator pool. Consumers cannot choose to opt for spot exposure, nor can they choose the trigger price.

The steps involved are as follows:

- The Commission forecasts the demand for electricity over a specified period, such as winter, and operates a competitive tender for call options backed by reliable generation capability to meet forecast demand
- Plant that wishes to participate in the tender must have the physical capacity and be willing to take on the obligation to provide the contracted amount of energy at the contracted call price, even in a very dry year. Diversity between wind and hydro schemes would be allowed for
- If insufficient dry year capability is offered from existing plant, the same contracts could be purchased from planned generation plant, and if still insufficient, the Commission would tender for new reserve energy
- Some monitoring would be likely to be required, for example, of fuel stocks, planned outages, etc. Penalty and prudential security regimes are also likely to be required to ensure that generators meet their commitments, and
- The cost would be allocated on all purchases, and the contracts allocated to the purchasers.

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<sup>64</sup> Consumers are fully insured against prices higher than the cap price, provided that total electricity demand is not greater than forecast demand.

Some advantages of the scheme are:

- It provides a contractual means for the Commission to obtain supply information from generators
- The comprehensive nature of the scheme means that it avoids some of the gaming issues that exist under other options
- It avoids the negative effects of contracting for only some capability, and
- It does not significantly affect normal market operations.

Some disadvantages of the scheme are:

- The Commission does not face incentives to minimise the cost of procurement
- Customers that might prefer to take some degree of spot exposure are not allowed to do so under this scheme, unless they do this by offering demand response capability into the tender
- Not all generators may wish to participate in the tender, particularly where the risk of failing to comply and potential penalties are high
- Capping the price at a trigger price of 20 c/kWh or similar may reduce incentives for demand response in dry years, and may require the Commission to actively seek demand response capability offers into the tender, and
- There may be transitional issues, for example, renegotiating existing hedge contracts in light of the compulsory insurance. (Generators will not want to contract with the Commission for energy they have already hedged with customers, and purchasers will not want to pay for insurance cover they already have).

**(ii) Centrally procured dry year insurance scheme with opt-out (NERA)**

As for the previous proposal, but levy is avoidable by ‘self-insurance’, and the Commission will procure contracts to meet net demand.

This would require that, where exemptions from the scheme are sought, the purchaser would need to prove that it had valid ‘self-insurance’ contracts or plant. Processes to assess the validity of alternate arrangements would need to be operated. In contrast to the WEMDG/CRA approach discussed in (iii), it would not be necessary to estimate the future demands of each purchaser individually.

In addition to those discussed above, some disadvantages of this scheme in particular are:

- Only time-of-use metered loads would be able to opt out due to the need to reconcile these customers separately
- Capability ratings will need to be assessed for all plant that relates to self-insurance contracts, and enforcement procedures developed. As discussed previously, rating hydro plant in particular will be difficult due to the differences between schemes, e.g. extent of storage, inflow variability, correlation with other plant, resource management constraints, etc. Historical data may not be sufficient in some or all cases to support such an assessment. Rating wind generation schemes will also carry risks both for the assessor and the generator
- Monitoring obligations on the Commission will increase with opt-out, and

- There is a risk that purchasers may opt out of the scheme when risks are low and opt back in when risks are higher.

### **(iii) Compulsory Dry Year Insurance (WEMDG)**

The scheme proposed by WEMDG prior to the development of the wholesale electricity market is effectively an extreme case of the NERA proposal, where all purchasers have opted-out of the centrally procured reserve energy and instead procure their own physically backed insurance contracts or face penalties for failing to do so. The prices which purchasers are insured against are determined by each purchaser (subject to some limits).<sup>65</sup>

Purchasers' future demands are estimated. Each purchaser is responsible for procuring capped contracts for some multiple of their estimated future demand.

With the exception of the last one, the disadvantages noted for the NERA approach also apply to this approach. In addition, the fully decentralised approaches require that obligations are imposed on purchasers to acquire insurance contracts or tickets commensurate with their retail load. This involves similar issues as with the ICAP/ACAP regime outlined earlier – high transaction costs for market participants, high administrative costs for the Commission, and complexities of forecasting future (changing) loads in the context of retail competition.

### **B.2.2 Morrison & Co's Enhanced Reserve Energy Proposal**

In a review of the proposed reserve energy for the MED, Morrison & Co proposed an enhanced approach to reserve energy procurement.

The 'planning' aspect of this proposal involves the Commission running a tender for reserve energy once a trigger point (defined in terms of the Minzone) has been reached. The tender is for the right to physically 'call' the plant to operate when the Minzone is reached. In return, providers would receive a pre-determined price for any energy provided when called, as well as an annual fixed fee determined through the tender. Any new plant (or old plant that would otherwise be decommissioned) or demand side response that was sufficiently 'firm' would be eligible to tender. Auditing of capability and availability, and penalties for failing to comply with contract terms would be required.

Unlike the current reserve energy regime, there would be no requirement for the plant to be ring-fenced. The plant owner would retain the right to dispatch the plant as it saw fit at all times that did not affect the Commission's rights. The Commission could on-sell the financial rights to power to the market (with proceeds offsetting the levy) but retain the physical dispatch rights.

The Enhanced proposal also includes provision to tender for comprehensive 'coordination rights' which is focused on ensuring efficient use of available resources *within* a potential dry year situation. Hydro plant with storage could offer to provide a minimum storage level at a specified time in return for a fee. Other generators could guarantee to offer a nominated level of energy over a specified time period while in the Minzone, also in return for a fee. As with the planning tender round, a penalty regime would be required to ensure performance.

The proposal also allows for generation plant that is not included in either tender to obtain a dry year capability rating. The rating, once assigned to a purchaser, would enable

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<sup>65</sup> CRA's adequacy tickets approach is similar to the WEMDG approach or NERA approach, depending on whether there is an element of central procurement.

it to offset its levy obligation. An approach to rating plant for dry year capability would need to be developed, and may be open to challenge if participants disagree with the Commission's assessment.

Some advantages of the proposal are that:

- It avoids the Commission needing to choose the mix of reserve energy sources—rather it selects the cheapest sources offered through the tender
- It improves the Commission's ability to obtain good information, through contractual processes, and
- It avoids reducing incentives for new investment in baseload plant (relative to the existing regime).

However, the revised proposal will involve greater administrative involvement and therefore cost.

**Table 9.4: Comparison of Proposed Energy Mechanisms**

	<b>Existing RE regime</b>	<b>Enhanced RE regime with exemptions (Morrison &amp; Co)</b>	<b>Centrally procured dry year insurance (Hansen)</b>	<b>Centrally procured dry year insurance with opt out (NERA)</b>	<b>Compulsory dry year insurance / adequacy tickets (WEMDG/CRA)</b>
<b>Who decides amount of RE/call options to buy?</b>	Commission determines net requirement to centrally procure	Commission determines net requirement to centrally procure	Commission determines gross requirement to centrally procure	Commission determines net requirement to centrally procure	Commission determines gross requirement, and allocates to purchasers
<b>How are RE/call options procured and from whom?</b>	Centrally procured RE in the form of 'physical call options' is procured through a competitive tender process	Centrally procured RE in the form of 'physical call options' is procured through a competitive tender process. Rated capability call options are procured by purchasers who have opted to self provide	Centrally procured call options are procured through a competitive tender process	Centrally procured call options are procured through a competitive tender process. Rated capability call options are procured by purchasers who have opted to self-provide	Purchasers are responsible for procuring call options for rated capability. There is no central procurement
<b>Who sells reserve energy?</b>	New plant or plant that would otherwise be retired may enter the tender	New plant or plant that would otherwise be retired may enter the 'planning' tender. Any rated plant may be used to offset the levy	Any rated plant may enter the tender	Any rated plant not committed to offset the levy may enter the central tender. Any rated plant may be used to offset the levy	There is no central procurement. Market participants trade 'rated' energy supply capability to meet obligations
<b>What is the price?</b>	Trigger price for operating RE set by Commission; Fixed annual facility fee determined by tender	Centrally procured RE: Trigger price for operating RE set by Commission; Fixed annual facility fee determined by tender  Price for self-provided RE set by contract parties	Centrally procured options: Trigger price for operating RE set by Commission; Fixed annual facility fee determined by tender	Centrally procured options: Trigger price for operating RE set by Commission; Fixed annual facility fee determined by tender  Price for self-provided RE set by contract parties	Price for all RE determined by contract parties

<b>Who controls dispatch of (makes offer decisions for) reserve energy?</b>	Commission	Commission for centrally procured RE, individual plant owners for self-provided RE	Commission	Commission for centrally procured RE, individual plant owners for self-provided RE	There is no centrally procured RE. Individual plant owners control dispatch of self-provided RE plant
<b>How to you ensure performance by reserve energy providers?</b>	Contracts include fuel availability requirements, plant/fuel availability audits, & penalty regime	Contracts with penalty regime, performance incentives from spot market prices	Performance incentives from spot market prices, prudential regime	Performance incentives from spot market prices, prudential regime	Performance incentives from spot market prices
<b>What price protection is provided?</b>	RE plant may be the highest price dispatched plant at times, but no explicit price insurance is provided as part of the RE mechanism	RE plant may be the highest price dispatched plant at times, but no explicit price insurance is provided as part of the RE mechanism. Contractually defined price protection for self-provided capability	Centrally procured options are allocated to purchasers, with price at which options are exercised determined by Commission.	Centrally procured options are allocated to purchasers, with price at which options are exercised determined by Commission  Contractually defined price protection for self-provided capability	Contractually defined price protection

Source: Castalia



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