



Concept Consulting Group

Assessment of
Reserve Energy
Requirements
for 2005

prepared for

Ministry of
Economic
Development

February 2004



Advice of Disclaimer

We have endeavoured to ensure the accuracy and completeness of this report. In view of the reliance on information prepared by others, we do not accept any liability for errors or omissions in our report or for any consequences of reliance on our conclusions.

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1 Introduction

In May 2003, the Government announced it would establish an Electricity Commission to ensure its electricity policy objectives are met. In relation to security of supply, the Electricity Commission is expected to ensure that electricity demand can be met in a 1-in-60 dry year without the need for national power conservation campaigns. Contracting for reserve energy will be one of the special measures available to the Commission when the Electricity and Gas Industries Bill (EGIB) is passed into legislation, probably around July 2004.

In advance of the Commission being established, the Ministry of Economic Development (MED) assumed responsibility for security of supply. The government has already procured 155MW of reserve energy from the new Whirinaki open cycle gas turbine power station. This is to be available for winter 2004 should it be needed. Security monitoring arrangements and contingency plans are currently being put in place by MED for winter 2004 security.

The Electricity Commission is not yet in a position to assume full responsibility for security of supply and the procurement of any reserve energy required for 2005. It will also need time to develop and consult on its longer term approach to security of supply and contracting for reserve energy in line with its responsibilities under the draft EGIB.

Given these factors and the likely lead time to procure any additional reserve energy required for 2005, the MED has initiated an assessment of security of supply for the winter of 2005. It is understood that this assessment and any related reserve energy procurement needs are seen as interim measures and are not intended to compromise the Electricity Commission's responsibility for defining and implementing longer term security policies.

Concept Consulting Group (Concept) was asked to assist in this assessment. This paper sets out Concept's analysis and conclusions.

2 Objectives

The Government's security of supply objective is that electricity demand can be met in a 1 in 60 dry year without the need for emergency conservation campaigns while minimising distortions to the normal operation of the electricity market. The Electricity Commission will be responsible for implementing this objective and will be required to develop, consult on and publish a security policy. Important aspects of this will be to:

- Define a 1 in 60 year security standard

- Put arrangements in place to effectively monitor the level of security being provided by the market
- Implement measures to ensure that the 1 in 60 security policy is achieved in practice
- Manage emergency conservation campaigns to avert material risks of supply shortages

In relation to the third point, the Electricity Commission will have a number of measures open to it including procuring information about hydro and thermal fuel stocks, contracting for reserve energy to extend security of supply to the 1 in 60 standard, requiring generators to hold energy reserves, requiring wholesale purchasers to hold hedges etc, and will also be able to make recommendations to the Minister on the need for new regulations.

For reasons noted in Section 1 of this report, we have been asked to consider what role additional reserve energy might fill in 2005 and to what extent additional reserves are needed. This would enable tendering and contracting to take place this year. It is believed that this would need to occur by mid 2004 if additional reserves are required for the winter of 2005.

3 Overall Approach

Our approach has been to consider what the 1 in 60 security policy might mean in practice and to what extent additional reserve energy might be needed in 2005 to meet this standard. That is, to bridge any gap between the level of security the electricity market could be expected to deliver in 2005 and a 1 in 60 year security standard. This has required us to make a number of assumptions as to how the Electricity Commission might approach its security of supply responsibilities. We expand on these issues in the following section.

The general approach we have followed is to assess firstly the technical dry year capability of the supply system relative to electricity demand in 2005. This has required assumptions to be made about thermal fuel supply, generation and transmission availability, demand and new supply projects. These assumptions have been developed in consultation with the Ministry of Economic Development. Detailed modelling of supply and demand was supported by Energy Link using its EMarket model with detailed hydro system and transmission elements included.

Having assessed the 'technical supply capability' of the system relative to estimated demand in 2005, we then assessed the risk to security of supply in terms of the assumptions made, possible market behaviours and the approach the Electricity Commission might adopt in the short term to its security of supply responsibilities,

including the role of the new Whirinaki reserve energy plant. We also undertook some historical analysis to assist in our assessment of security risks in 2005.

Similar analysis was also undertaken for 2006, although in less detail given the time available. The objective of this was to assess security levels in 2006 noting that at this stage while a number of possible new projects have been signalled, delays in Genesis' e3p combined cycle gas turbine (CCGT) project coming on stream suggests that new supply could be limited in 2006. Supply and demand in 2007 have not been specifically assessed in the time available but analysis for 2006 with and without e3p provides useful insights into 2007. The rationale for assessing the later years is that the need for energy reserves might alter over time and this could influence the nature of procurement options. For example, a short term requirement might best be met by procuring a demand side or less capital intensive option.

The remainder of this report covers:

- The need to make assumptions about how the Electricity Commission might interpret and implement the Government's 1 in 60 dry year security policy objective
- Modelling - key assumptions and analysis
- Conclusions

4 Policy Considerations

4.1 Historical Perspective

Until 1992 the system was operated to a so called 1 in 20 year security of supply standard. This standard was operationalised by ensuring that sufficient hydro storage was maintained so that demand could be met should a 1 in 20 dry year inflow sequence occur. At that time, the hydrological record was limited to sixty years of data and the 1 in 20 year standard was in effect based on supply being sufficient to withstand the third worst historical inflow sequence looking forward from that point¹.

The concept of a 1 in 60 year security standard was adopted as an interim measure following the recommendations of the Davison Enquiry² into the 1992 hydro shortage.

¹ Operationally, assumptions were also made about the cost of non supply/ conservation in a severe inflow event and when peaking gas turbine plant would be operated. A number of so called reserves were also excluded from normal operational planning to cover a range of abnormal or emergency risks.

² "Electricity Shortage 1992", The Report of the Electricity Shortage Review Committee – 1992.

At that time, operating the system to a 1 in 60 standard implied that the worst historical inflow sequence looking forward at any time of the year would just avoid supply shortages. The enquiry team considered the one off cost of shifting to the higher standard at that time to be relatively small given existing plant capacity.

4.2 Government Policy

Following security of supply concerns in 2001 and 2003, the Government set out its security of supply policies in a draft Government Policy Statement (GPS) released in September 2003. The core objective is that security of supply be maintained to a 1 in 60 dry year security standard. The Electricity Commission will be required to use reasonable endeavours to ensure this objective is achieved. The practicalities of exactly what is meant by the concept of a 1 in 60 dry year security policy will need to be determined by the Electricity Commission. The GPS clearly contemplates that emergency conservation measures would be required for extreme rare dry year events. The GPS objective of ensuring that security of supply is maintained at the 1 in 60 dry year level means that the worst historical inflow sequences would not necessarily be covered (as intended with the interim standard adopted after 1992, when the historical hydrology record only spanned 60 years).

Technically the concept of a 1 in 60 dry year standard could be considered statistically in terms of low inflow event return periods. However, it is beyond the scope of this report to undertake and apply this sort of analysis and clearly an Electricity Commission responsibility to consider. The Commission may also wish to consider combinations of dry year and plant risks with a similar return period and whether factors such as mid range climate / inflow forecasts or any statistical evidence of inflow trends in recent years might be accounted for (or not).

4.3 Interim Approach Taken

For the time being, we have simply adopted the historical approach of assuming that historical inflow sequences have equal probability looking forward in time. On that basis, the concept of a 1 in 60 dry year policy implies crudely that emergency conservation measures could be needed if inflows were to be sustained at levels lower than the worst historical inflow sequence looking forward from any time of the year. Just as the 1 in 20 standard meant roughly that shortage would just be avoided for the third worst of 60 historical inflow sequences, it could be assumed for now that a 1 in 60 policy with 72 years of historical inflow records implies that at least one, but not two, historical inflow sequence looking forward at any time of the year could result in shortage.

It is of course possible that more than one or two historical inflow sequences have return periods in excess of 60 years and our approach is perhaps therefore a little conservative, but prudently so.

Importantly, as discussed in the following section, the historical implementation of a 1 in x dry year standard did not necessarily mean that the risk of emergency conservation campaigns was 1 in x at all times. In practice, the risk at any particular time would have generally been less than 1 in x. For example, under the historical 1 in 20 policy, security of supply would have been maintained to 'at least' a 1 in 20 year level with intervention required if the level of security risk reached the nominal 1 in 20 level. We have adopted a similar approach as outlined in the following.

4.4 Security Policy Implementation Issues

In addition to interpreting the Government's 1 in 60 year security policy objective, the Electricity Commission will need to develop means of assessing security operationally. It will clearly be some time before the Electricity Commission has considered these issues properly.

We have therefore had to make a number of assumptions in the interim. In particular, for part of our analysis, we have used the minimum storage zone technique for establishing critical storage levels with respect to security of supply. This was developed within the Winter Task Force project in 2003. The minimum storage zone approach has also been used in the Ministry of Economic Development project to assess security of supply risks for 2004. The Electricity Commission will no doubt consider alternative approaches but could adopt or adapt this technique (noting that it is also referred to in the GPS as an option). The minimum zone approach is explained in Section 5.1.2.

In respect of reserve energy required to extend security of supply to the 1 in 60 level, the Electricity Commission will be able to contract for both supply and demand side reserves. The GPS indicates that these would be triggered should the spot price reach 20c/kWh³ or when security guidelines (for example, minimum hydro storage levels) set by the Electricity Commission is reached. We have had to make some assumptions about how the Electricity Commission will use existing reserve energy contracts, noting that the 155MW Whirinaki plant will be under its control in 2005.

5 Modelling and Analysis

5.1 Models

We have relied on two models to carry out our analysis – the Energy Link EMarket model and a minimum hydro storage zone model (Minzone).

³ Or higher if the variable cost of the contracted reserve is greater than 20c/kWh.

5.1.1 Emarket

EMarket is a sophisticated electricity market model which includes:

- Supply on a station by station basis including detailed representations of the Clutha, Waitaki, Waikato and Manapouri-Te Anau hydro catchments
- A detailed representation of the National Grid featuring 184 nodes with dispatch and pricing on the same basis as the electricity market, including marginal losses and line constraints
- Hydro generator optimisation relative to thermal generator offers which can be constructed to replicate observed or expected commercial strategies
- A degree of flexibility to simulate a variety of supply and demand scenarios

EMarket is used in our analysis to simulate market conditions and in conjunction with the Minzone model to assess the technical supply capability of the system in a dry year. Energy Link carried out modelling runs as requested.

5.1.2 Minzone

A minimum hydro storage zone defines the minimum storage profile which must be maintained over the year to ensure that, should low inflows occur, security can be maintained with all non hydro supply committed to the extent technically practical. We have used EMarket to simulate non hydro generators operating to their practical limits, subject to fuel supplies in the case of thermal plant, to reduce hydro storage releases to the minimum required to supplement supply to meet demand. By doing this for each month of the year in question, hydro storage levels can be projected under a range of historical inflow sequences. EMarket results are then used to populate a separate Minzone model which identifies the worst (or if selected, the second or third worst) inflow sequence for each month which sets the minimum zone for that month. Minzone can look ahead a selected number of months (up to a year) to assess the extent to which storage falls under the worst (or second, third worst etc) inflow sequence over that timeframe. The drop in storage determines the minimum storage requirement as depicted in Figure 1.

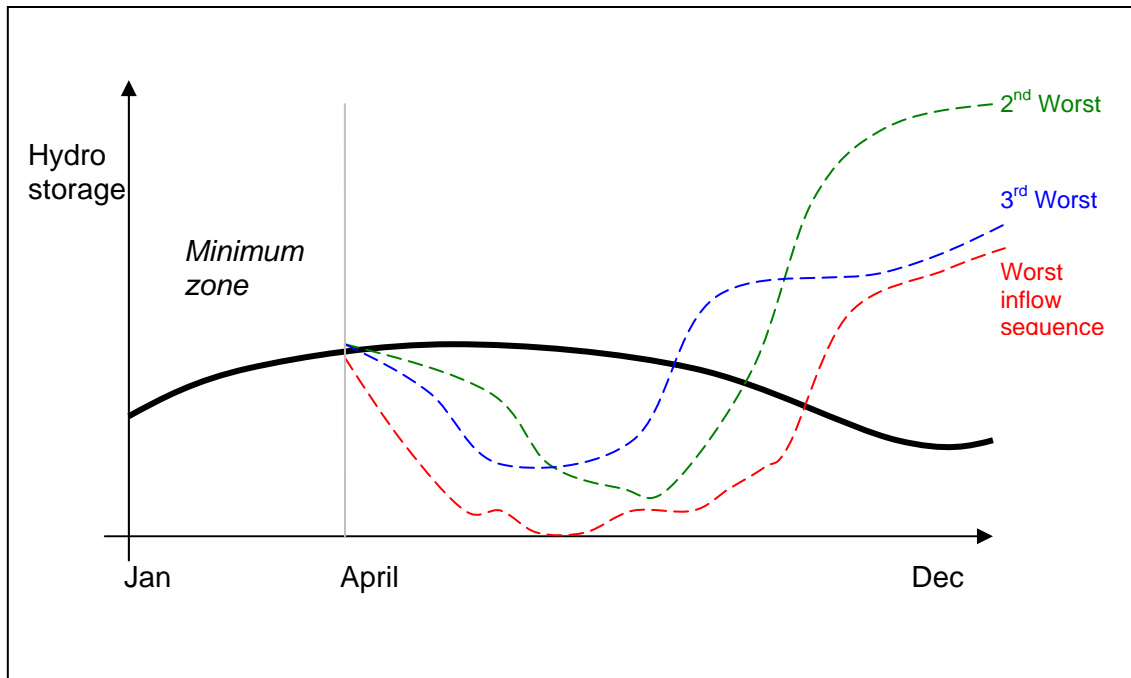


Figure 1: Illustrative Minzone Approach

In Figure 1, the April Minzone storage level illustrated is based on the worst inflow sequence. As noted in section 4.3, a possible policy implementation is that the worst inflow sequence from over seventy years of records has a return period in excess of 60 years. The Minzone would be lower if the second worst inflow sequence looking forward from April was deemed to have a return period of 60 years or more for example. Similarly, although not shown in Figure 1, the look ahead period can affect the Minzone as well. For the purpose of our analysis we have generally adopted a conservative 12 month look ahead period.

An important consideration in our analysis is the likelihood of storage falling to the Minzone level. Another critical issue is the extent to which non hydro supply capability assumptions can be relied upon, especially in relation to thermal fuel. We discuss these issues later but first set out key modelling assumptions. These generally apply to EMarket modelling for both Minzone and normal market simulations although in some instances different assumptions have been used for each category of modelling.

A significant amount of analysis has been undertaken by Concept in support of the Ministry of Economic Development's 2004 security of supply workstream to assess the sensitivity of Minzone analysis to key physical and modelling uncertainties and approximations. This is described in the Report "Energy Security Assessment: Modelling and Analysis – MED February 2004" and not repeated here. Reference is made to that work where relevant in this report. As a result of that analysis, we are comfortable that adopting a NZ storage Minzone profile is sufficiently accurate given

the range of uncertainties generally involved in this sort of analysis. The interaction between North and South Island reservoirs probably warrants further scrutiny.

5.2 Key Assumptions

5.2.1 Demand

Demand projections have been extrapolated from a base demand period from April 2002 to March 2003. This period was selected as it is the most recent complete annual period least affected by saving campaigns. Demand growth of 2% pa was agreed with the Ministry of Economic Development. Emarket model runs were undertaken using simple rather than compounding growth rates. A monthly breakdown of the demand assumptions for 2005 / 6 Emarket model runs is summarised in Table 1.

Table 1 - Demand Assumptions

Base Demand		Increase on Base Demand		
Mnth-Yr	GWh	2004	2005	2006
Apr-02	3,355		6%	8%
May-02	2,809		6%	8%
Jun-02	2,885		6%	8%
Jul-02	3,735		6%	8%
Aug-02	2,961		6%	8%
Sep-02	3,519		6%	8%
Oct-02	2,720		6%	8%
Nov-02	2,737		6%	8%
Dec-02	3,168		6%	8%
Jan-03	2,637	4%	6%	
Feb-03	2,691	4%	6%	
Mar-03	3,347	4%	6%	
Total	36,564			

Note: The base demand data in this table does not align exactly with the detailed data used in EMarket. ie monthly demand data in this table has been approximated from weekly figures – some months having 5 weeks apportioned to them, others only 4 – and the annual total includes 53 weeks of demand.

The impact of using a simple rather than compound growth rate of 2% is not considered to be material to our analysis (the impact being about 0.1% or 40 GWh in 2005 and 0.2% or 80 GWh in 2006). The growth rates were applied equally to each Island.

5.2.2 Existing Thermal Stations

We were advised by the Ministry of Economic Development to assume that existing thermal stations, including the 155MW Whirinaki reserve energy plant, would not be fuel constrained in a dry year. This is clearly a critical assumption. It makes the approach to modelling much simpler and meant that the Ministry of Economic Development did not need to disclose individual thermal fuel contract, fuel stock and fuel supply arrangements to Concept. It is understood that the Ministry of Economic Development has received assurances about thermal fuel supply, including delivery and stock constraints, which enable it to adopt this critical assumption.

Thermal stations have therefore been assumed to be fully available subject to capacity de-ratings to reflect outages, Huntly river heating limits and ancillary service requirements.

Table 2 summarises assumptions with respect to nominal station capacities and planned outages.

Table 2 - Thermal Planned Outage Program⁴

Station	Nominal Rating	Derating	2005		2006	
			Out	In	Out	In
Otahuhu B	360MW	Total Stn	27-Dec-04	17-Jan-05	26-Dec-05	16-Jan-06
		Total Stn	18-Jul-05	25-Jul-05	17-Jul-06	24-Jul-06
		Total Stn	26-Dec-05	16-Jan-06	25-Dec-06	15-Jan-07
		Total Stn	17-Jul-06	24-Jul-06	16-Jul-07	23-Jul-07
		Total Stn	25-Dec-06	15-Jan-07	24-Dec-07	14-Jan-08
New Plymouth	400MW	100MW	24-Jan-05	18-Apr-05	23-Jan-06	17-Apr-06
		100MW	5-Sep-05	3-Oct-05	4-Sep-06	2-Oct-06
		100MW	23-Jan-06	17-Apr-06	22-Jan-07	21-Apr-07
		100MW	4-Sep-06	2-Oct-06	3-Sep-07	1-Oct-07
Wairakei	158MW	30MW	14-Feb-05	21-Mar-05	13-Feb-06	20-Mar-06
		11MW	11-Apr-05	9-May-05	10-Apr-06	8-May-06
		30MW	13-Feb-06	20-Mar-06	12-Feb-07	19-Mar-07
		11MW	10-Apr-06	8-May-06	9-Apr-07	7-May-07
Taranaki CCGT	350MW	Total Stn	3-Oct-05	28-Nov-05	2-Oct-06	27-Nov-06
		Total Stn	2-Oct-06	27-Nov-06	1-Oct-07	26-Nov-07
Huntly	1000MW ⁵	250MW	6-Dec-04	28-Mar-05	5-Dec-05	27-Mar-06
		250MW	5-Dec-05	27-Mar-06	4-Dec-06	26-Mar-07
		250MW	4-Dec-06	26-Mar-07	3-Dec-07	24-Mar-08
Southdown	100MW	42MW	26-Sep-05	3-Oct-05	25-Sep-06	4-Oct-06
		42MW	25-Sep-06	4-Oct-06	24-Sep-07	3-Oct-07

The thermal units have been further de-rated to allow for forced outages. A summary of assumed forced outage rates is shown in Table 3. These assumptions are consistent

⁴ Planned Outages are based on the outage programme for 2004. The Ministry is to confirm these assumptions with the generators if practical.

⁵ It has been suggested recently that Huntly's maximum capacity on coal is 972MW. The impact of changing this would tend to balance correcting the conservative allowance for Huntly providing short term reserves as discussed later in this section.

with those we have used in evaluating system security for 2004⁶. These estimates were developed from statistical analysis of similar power stations in North America.

Table 3 - Forced Outage Assumptions

Plant	Forced Outage Rates
Otahuhu B	2%
TCC	2%
Huntly ⁷	3%
New Plymouth	4.5%

Further, and again consistent with system security analysis for 2004, we have de-rated Huntly to allow for potential cooling water restrictions. Table 4 summarises the river heating capacities used in current modelling.

Table 4 - Huntly River Heating Capacity

Station MW Limits		
	Day	Night
Jan	700	750
Feb	600	740
Mar	750	750

Note: Day is 0800 – 2400 and Night is 2400 – 0800

The Minzone model runs are based on the technical supply capability of the system at times when there is limited hydro capacity. In these circumstances, thermal plant may be relied on to provide additional short term reserves for real time system security and

⁶ Energy Security Assessment: Modelling and Analysis – MED February 2004

⁷ Since the model runs were carried out, Genesis has recommended that allowance also be made for maintenance outages (outages that can be scheduled at short notice to carry out necessary maintenance, typically on weekends). As with station capacity assumptions (refer footnote 5), this would tend to offset conservatism in reserves and frequency keeping derating.

frequency control services which would otherwise be provided by hydro stations. These services are detailed in the Ministry of Economic Development report “Energy Security Assessment: Modelling and Analysis” for 2004 and are treated as a further derating of Huntly by 190 MW overnight and 100 MW during the day⁸. We consider that the daytime limit is conservative (ie too much short term reserve limiting Huntly more than is likely to actually occur). We note that the possible reduction in Huntly maximum capacity on coal noted previously (footnote 5) would tend to offset this conservatism. Any further reduction to the short term reserve derating would tend to decrease the Minzone storage levels subject to transmission constraints becoming more binding. For market simulation using EMarket, no short term derating was applied to Huntly to account for short term reserve requirements. This is because under normal market conditions, short term reserves from generators can typically be supplied from a combination of hydro plants and partly loaded thermal plants.

The combined effect of planned outages, forced outages and reduced output due to Huntly river heating constraints and reserve requirements on thermal plant capacity for Minzone model runs is depicted in Figure 2:

⁸ From a system technical capacity perspective it does not matter which thermal stations are de-rated if all are fully fuelled. However, Huntly is able to provide the frequency control service and is a good quality reserve provider.

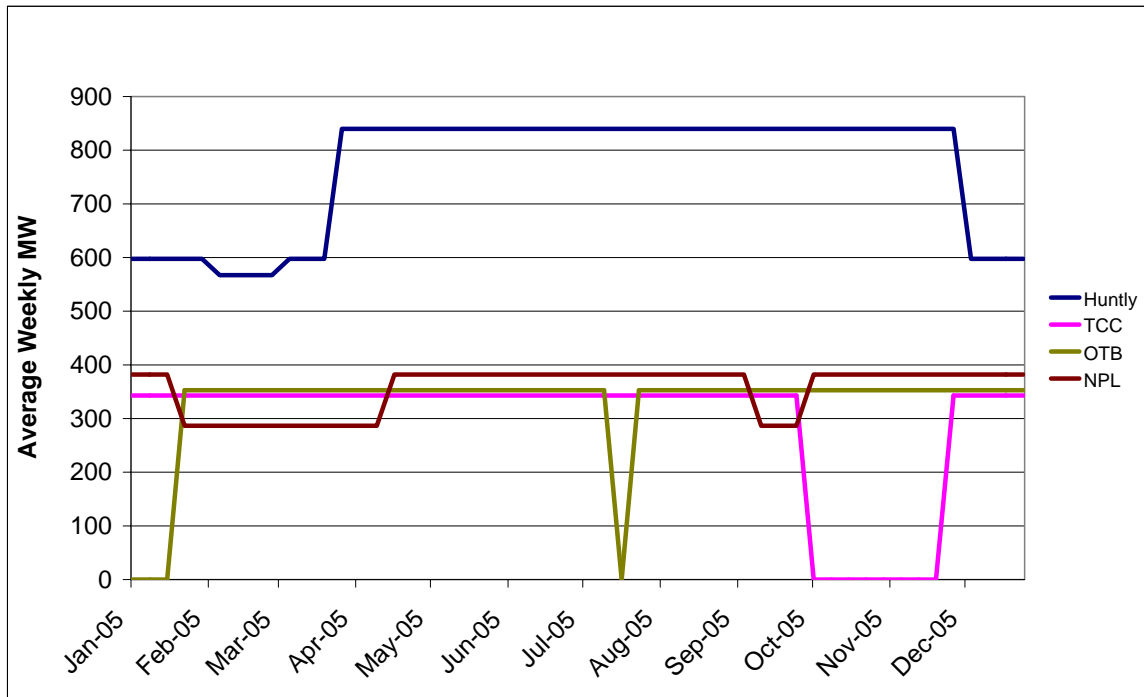


Figure 2 – Average Modelled Thermal Capacities for Minzone Modelling

Note: Huntly figures are the weighted average of the modelled day / night constrained levels in each week.

5.2.3 Limitations of Approach to Thermal Availability

Ideally thermal forced outages would be modelled using random techniques (such as a Monte Carlo approach). Constraining station availability by x% to reflect a forced outage rate of x% should be similar in effect to randomly shutting the station down x% of the time in energy terms. However, to the extent that there are at times constraints on a station’s ability to generate, for example due to lower demand overnight or transmission constraints or both, the approach we have taken could tend to overstate the impact of an outage at these times or to understate the effect at other times. In the time available, Concept has not been able to fully evaluate these effects. For example, in a dry year, reducing thermal station capacities by a few percent throughout the year to simulate forced outage rates (when compared to the reality of random unit outages occurring for a few percent of the time) could cause thermal stations to operate more in the model during the night when southward transmission constraints (discussed later) tend to impact on North Island thermal supply. This could potentially cause Minzone storage estimates to be lower than otherwise. To assess this effect properly would require detailed analysis of the two approaches to ascertain the impact of transmission constraints. This would require simulation of forced outages, for example using the

Monte Carlo technique, compared to applying the average capacity deratings across the year.

5.2.4 New Supply Assumptions

In terms of new supply, a schedule of new investments was agreed with the Ministry of Economic Development reflecting committed or highly likely projects up to April 2006. These assumptions are shown in Table 5.

Table 5 - Assumed New Supply to 2006⁹

Year	Owner	Scheme	Rated Capacity (MW)
2004	Trustpower	Tararua Wind Farm Stage II	36
	Government	Whirinaki OCGT Reserve Energy	155
	Meridian Energy	Manapouri Hydro Scheme re-runnering	16
2005	Genesis Power	Huntly Gas Turbine	40
	Genesis Power	Hau Nui Wind Farm Expansion	8
	Contact Energy	Wairakei Geothermal Plant Expansion	10
	Tuaropaki Trust	Mokai Geothermal Plant Expansion	40
	Meridian Energy	Te Apiti Wind Farm	85
	Various	Cogeneration / Other	5
2006	Top Energy	Ngawha Geothermal	20

Manapouri enhancements have been modelled as efficiency and capacity changes enabling the impact to be accurately assessed.

Appropriate load factors have been agreed with the Ministry of Economic Development for each type of new supply. These are detailed in Table 6.

⁹ Since completing this analysis there have been some minor changes to the rated capacities of some of these projects. The overall effect to Minzone storage would be minimal.

Table 6 - Average Load Factors

New Supply Type	Average Load Factor
Wind	42%
Geothermal	95%
Cogeneration	95%
Gas Turbine	85%

5.2.5 Transmission

The EMarket model was used to evaluate the effect of transmission constraints. Key transmission limits are able to be mimicked by setting combinations of lines to preset limits. Although this is not as accurate as the full nodal representation used in the market scheduling and dispatch model (SPD), which is also only an approximation to the detailed physical characteristics of the grid, it is considered to be appropriate for this analysis.

Analysis has focussed on HVDC southward flows and the flows through the Bunnythorpe - Haywards (southwards) and Stratford - Brunswick (southwards) areas. Previous analysis¹⁰ has confirmed that these transmission constraints are the most likely to constrain North Island thermal supply during dry years.

For Minzone analysis, Energy Link applied the line limits detailed in Table 7.

Table 7: Transmission Constraint Assumptions

Transmission Lines	Winter		Summer	
	Day	Night	Day	Night
Bunnythorpe – Haywards	800 MW	930 MW	670 MW	930 MW
Stratford – Brunswick	690 MW	690 MW	550 MW	690 MW
HVDC North	1040 MW	1040 MW	1040 MW	1040 MW
HVDC South	626 MW	626 MW	626 MW	626 MW

Notes: Summer refers to the period commencing on 20 October and finishing 9 May. Winter refers to all other periods.

Night refers to 23:00 to 07:00 hours and on weekends between 22:00 and 17:00 hours. Day refers to all other periods.

¹⁰ Evaluation of security of supply risks for 2004; Concept Consulting Group, 4 July 2003 and 9 July 2003.

The 930 MW constraint on the Bunnythorpe – Haywards lines and the 690 MW constraint on the Stratford – Brunswick lines require Transpower to reconfigure the grid¹¹. This reconfiguration enables greater flows through these circuits but reduces the inherent security of supply to some customers elsewhere. Achieving these limits in practice is therefore subject to a number of conditions being met. One of these conditions currently includes demand conservation having been called for. We have assumed for this analysis that higher line flows (ie 930 MW) would be achieved in practice leading into a severe security situation. While demand conservation measures as such might not be triggered by the Electricity Commission at a 1 in 60 security threshold such as the Minzone, reaching a 1 in 60 security threshold is clearly a serious security threat.

Transpower has advised that the Bunnythorpe – Haywards limit could be extended to 990MW with an estimated capital expenditure of \$3-5m. This may be in place by winter 2006 but for our analysis we have assumed only the current lower flow limit.

5.3 2005 Assessment

Our analysis of security of supply in 2005 involved evaluating:

- The technical dry year supply capability of the system in 2005 (Minzone)
- The likelihood of low hydro storage levels in 2005 relative to Minzone storage levels

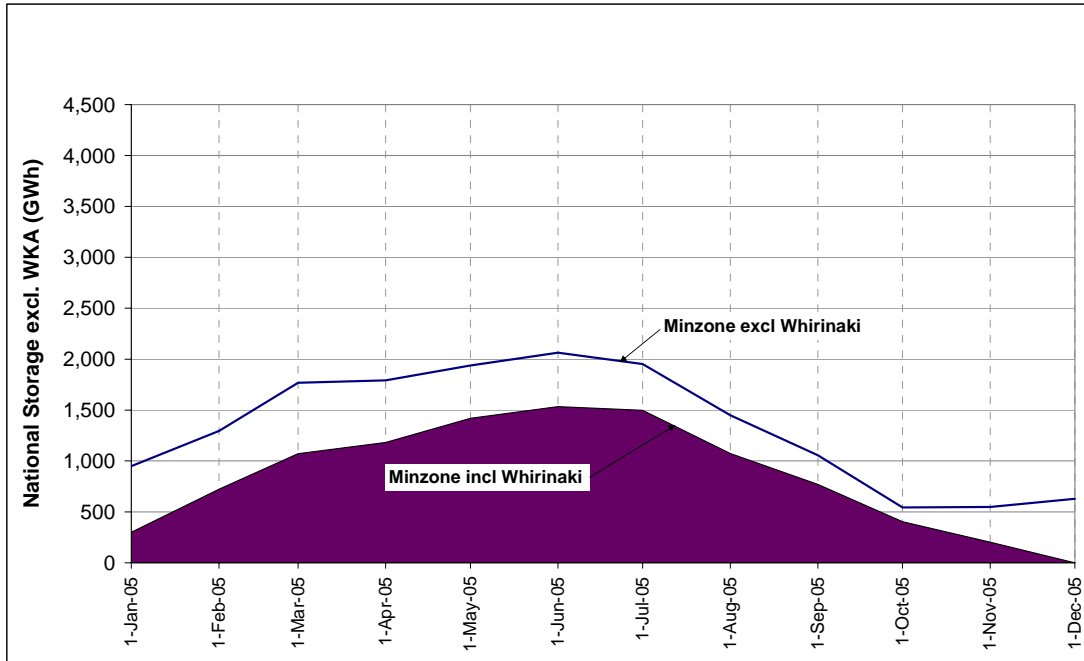
Some contingency analysis was also undertaken to assess the possible impact of a large thermal contingency event on security of supply in 2005.

5.3.1 Capacity of the System in 2005

Minzone modelling runs were undertaken with and without the Whirinaki reserve energy plant to test the sensitivity of having this new reserve energy plant fully available in 2005. The results are shown in Figure 3. We note that the impact of Whirinaki on the minzone as depicted in Figure 3 is possibly overstated given concerns over the way thermal capacities have been modelled. Examination of detailed model results indicates that southward transmission flows frequently reach constraint limits overnight. Higher thermal station output could therefore tend to displace Whirinaki more than is occurring in the model runs. It could be expected that the effect of this on the minzone including Whirinaki would tend to be offset by this additional thermal generation. In the time available it has not been practical to evaluate this fully.

¹¹ For example, refer to Transpower document “Protocol for the Implementation of Transmission Based Solutions to Increase North/South Energy Transfer in Winter 2003”.

Figure 3 - Minzone Guideline for 2005 Based on Worst Inflows



Subject to these observations, Figure 3 demonstrates the minimum storage profile that would need to be maintained in 2005 to ensure supply could meet demand (noting that no demand response has been assumed). Using the approach described in section 5.1.2, the Minzone storage for each month is set by the technical supply capability of the system under the lowest historical inflow sequence looking forward from that month for up to a year.

As discussed previously, this is likely to be more conservative than the 1:60 dry year policy implies because it is likely that the low inflow sequences setting each Minzone storage point have return periods of greater than 60 years. Some demand reduction in response to rising spot prices could also be expected and this would tend to enhance security. While difficult to identify, it is clear that in 2001 and 2003 a degree of price related demand response occurred before calls for emergency savings were made in each case. Nevertheless we believe it is appropriate to retain this degree of conservatism to offset other uncertainties in the modelling process.

The apparent reduction in benefit of Whirinaki in later months (ie the reduced difference between with and without Whirinaki runs) is due to the shorter duration of inflow of sequences driving the Minzone in later months. In June the historical inflow sequence driving the Minzone reaches zero in November so Whirinaki is contributing energy for 6

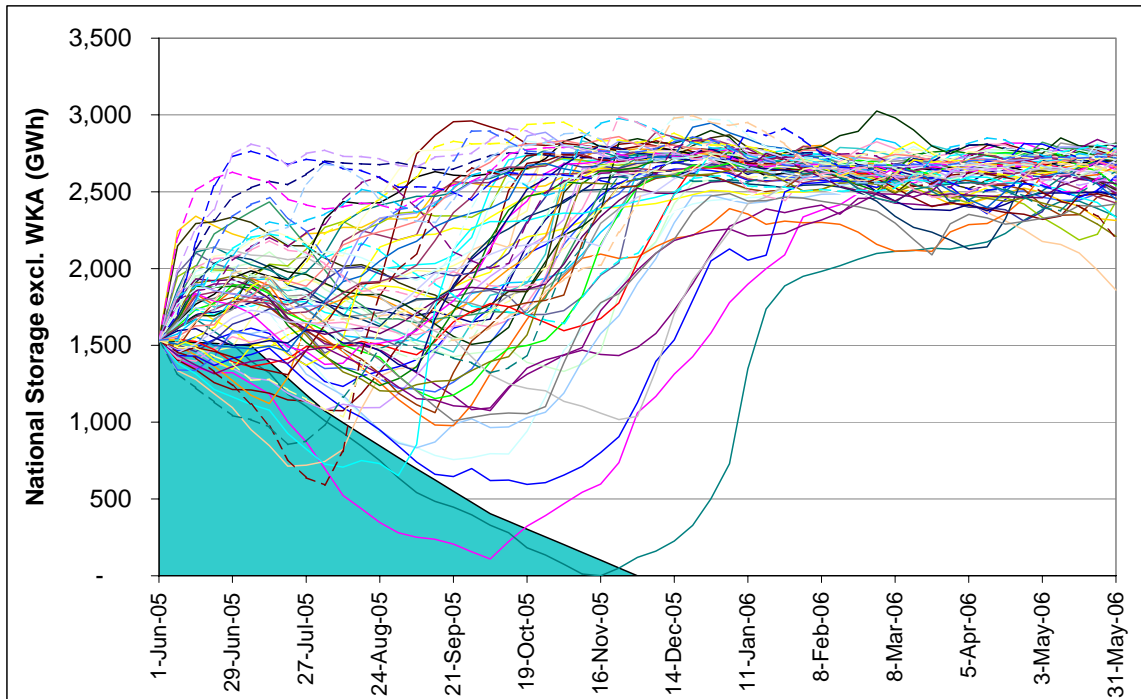
months (assuming no plant or fuel constraints). For October, the historical inflow sequence driving Minzone reaches zero again in November so Whirinaki is not able to contribute as much energy as in the June scenario.

5.3.2 Supply Implications if 2005 Minzone is Reached

The Electricity Commission will need to decide at what point Whirinaki (and any other reserve energy contracts) is committed. We believe it is reasonable to assume that an operational Minzone would commit Whirinaki. The purpose of the reserve energy scheme is to extend security of supply to the 1 in 60 level. (In practice, if there are additional reserves, it is likely that these would not all be committed at the same time depending on costs and cost structures but for now we are comfortable with our working assumption about Whirinaki being included in the Minzone.)

As noted previously, the risk of non supply is 1:72 at the Minzone storage level. As depicted in Figure 4, for most inflow sequences assuming all non-hydro is running to assumed capacity, storage recovers moving very quickly back out of the Minzone storage range. (The Minzone storage profile for June to Dec 2005 is highlighted as the shaded area in the graph).

Figure 4 – Storage Projections from June 2005 With All Non Hydro Fully Committed



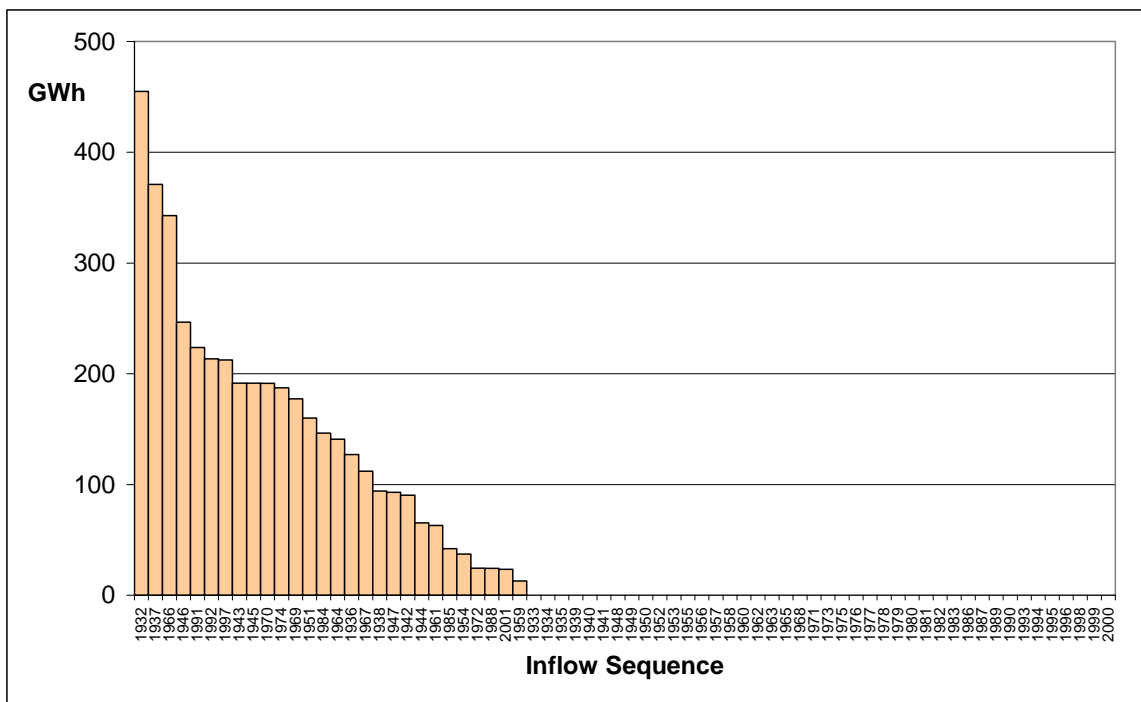
Putting aside for the moment concerns about the potential impact of transmission constraints on Whirinaki’s ability to generate overnight, Figure 5 shows the amount of modelled Whirinaki running (in GWh) from the 1st June 2005 for each inflow sequence assuming a Minzone start storage (1533 GWh)¹². We have excluded Whirinaki operation from the Minzone run results whenever storage is above the Minzone storage¹³.

¹² It is possible that there would be a degree of serial correlation between low inflows in one period and the next such that the chance of sustained low inflows continuing once the Minzone is reached are likely to be higher in some instances than this simplistic analysis suggests. This would tend to suggest that the distribution in Figure 5 could extend further to the right. On the other hand, it is also likely that in some instances the reverse is true suggesting that the height of the bars on the left hand side of Figure 5 would be lower.

¹³ It is also possible that storage could recover above the Minzone when Whirinaki is brought into service and then fall back below the Minzone once Whirinaki is removed from service, possibly understating the amount of Whirinaki operation for a few inflow sequences.

The objective is to illustrate broadly how much Whirinaki could be expected to operate should storage fall to the Minzone level. Importantly, Figure 5 is not an illustration of the likely amount of Whirinaki operation in 2005 – it ignores the fact that the chances of storage falling to the Minzone level are small as discussed in section 5.3.4.

Figure 5 Whirinaki GWh assuming Minzone 1st June start level



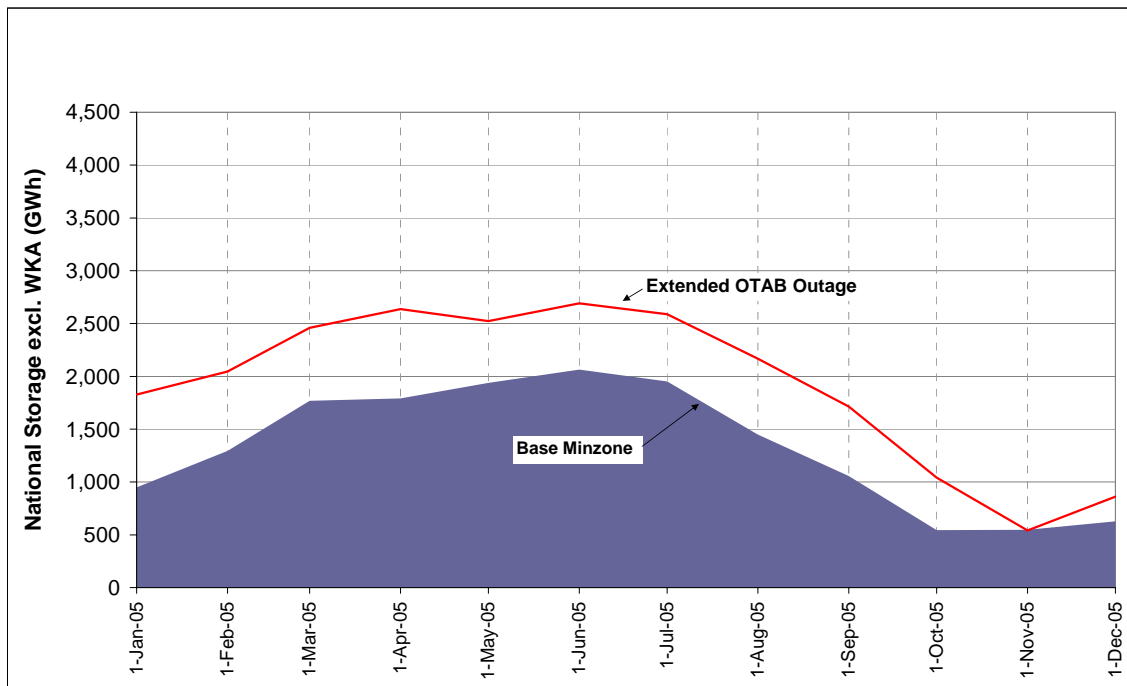
It can be seen that for most inflow sequences, Whirinaki is not required as the storage immediately increases above the Minzone storage level. Should storage fall to the Minzone level, requiring Whirinaki to run, then in most instances where this occurs the moderate running of Whirinaki is required (less than 250GWh). It can be seen from Figure 4 that for these inflow sequences, storage tends to recover above the Minzone in less than 2 months. There are a few inflow sequences where modelling suggests that Whirinaki would be required to run at high load factors. We have some concerns about whether this would be practical, except during other thermal plant outages, as the modelled results may understate the potential impact of transmission constraints.

5.3.3 Possible Contingent Events

Consistent with the analysis described in the “Security of Supply Assessment for 2004” report issued by the Ministry of Economic Development, an extended 3 month forced outage of a combined cycle station is considered a low probability but credible contingent event. Other contingent events, such as loss of a unit at Huntly, would have lesser impact and so fall within the risk envelope of the selected contingency.

Figure 6 demonstrates the impact of a 3 month extended Otahuhu B outage on the Minzone storage profile excluding Whirinaki. The outage is assumed to occur at the start of each Minzone run for three months.

Figure 6 - Impact of OTAB Outage on 2005 Minzone (excluding Whirinaki)



The convergence in Nov 2005 is due to the 11 month inflow sequence driving this point not being affected by the 3 month OTAB outage at the start of the sequence – that is inflows through the first 3 months being high, demand low and other thermal plant fully compensating for the OTAB outage.

Clearly the combined risk of an extended forced outage of one of New Zealand’s largest single thermal units occurring at the same time as a 1:60 dry year would have a return period well in excess of 60 years (or in this case 1:72 years). Accordingly, it would not be expected that storage would be maintained above the minimum storage

levels depicted in Figure 6 at all times. It may be prudent of course to move to this level in the event of a prolonged outage of a large thermal unit.¹⁴ In a dry year, it would be expected that southward transmission constraints would not limit the potential contribution of Whirinaki and its impact of the base minzone would be significant. For example, it could replace over 40% of Otahuhu B's output.

5.3.4 Simulated Storage Levels in 2005

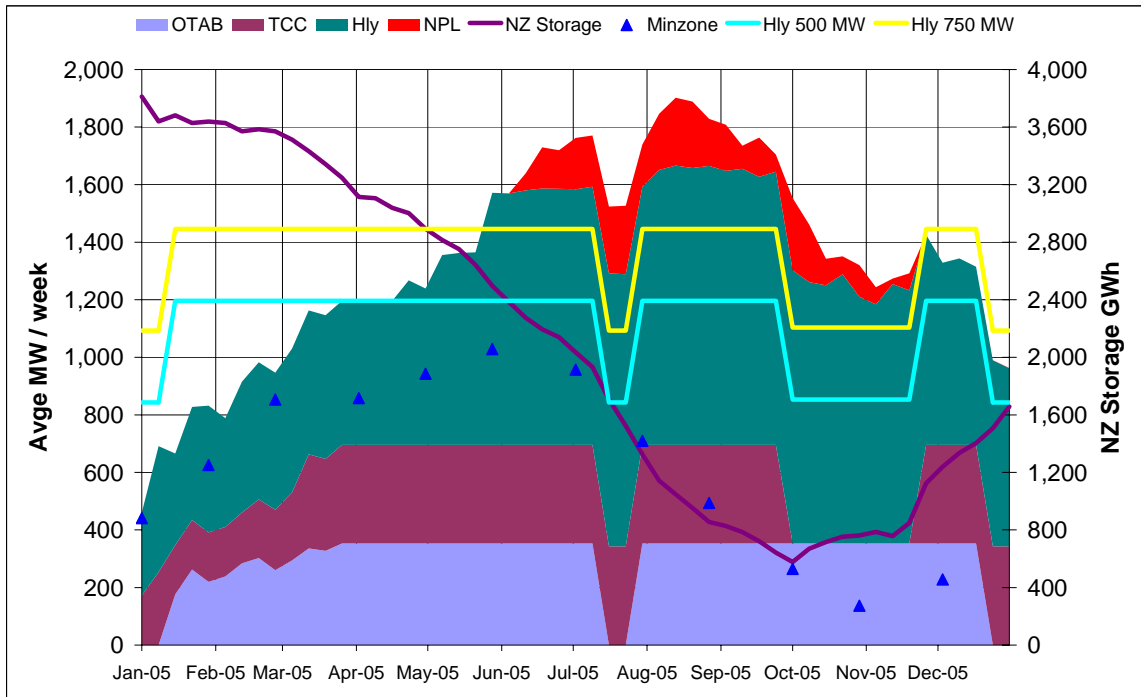
Figure 3 reflects the technical supply capacity (Minzone) of the system in 2005 should it be a dry year. The likelihood of storage falling to the Minzone level is more difficult to assess as it requires behavioural factors to be considered. We observe, however, that behaviour above the Minzone is less critical from a physical security of supply perspective than being able to rely on all supply operating to assumed limits should storage fall to the Minzone level. (Reaching the Minzone level too often could cause other concerns, such as those associated with high spot prices). The real behavioural concern is whether plant will respond as assumed when the Minzone is reached but the likelihood of hitting the Minzone is still an important consideration.

EMarket was used to simulate what hydro storage levels may do over the next 24 months from current (February 2004) storage and based on 72 years of inflow data. This was completed in two steps – initially a run was completed for 2004 giving a range of start storages for 2005. In considering these results, we first assessed how EMarket was dispatching generation to ensure that this was occurring in a sensible manner. To illustrate our approach to this assessment, Figure 7 shows the modelled thermal dispatch in a dry year (1932) with the Minzone excluding Whirinaki overlaid¹⁵.

¹⁴ If such a contingent event was deemed to have a return period of say 1 in 12 years, then it may be sensible to consider a Minzone based on such an event under a 1 in 5 dry year.

¹⁵ Minzone without Whirinaki was used as the market should consider this as “reserve” capacity only and the EC will decide at what point it is introduced.

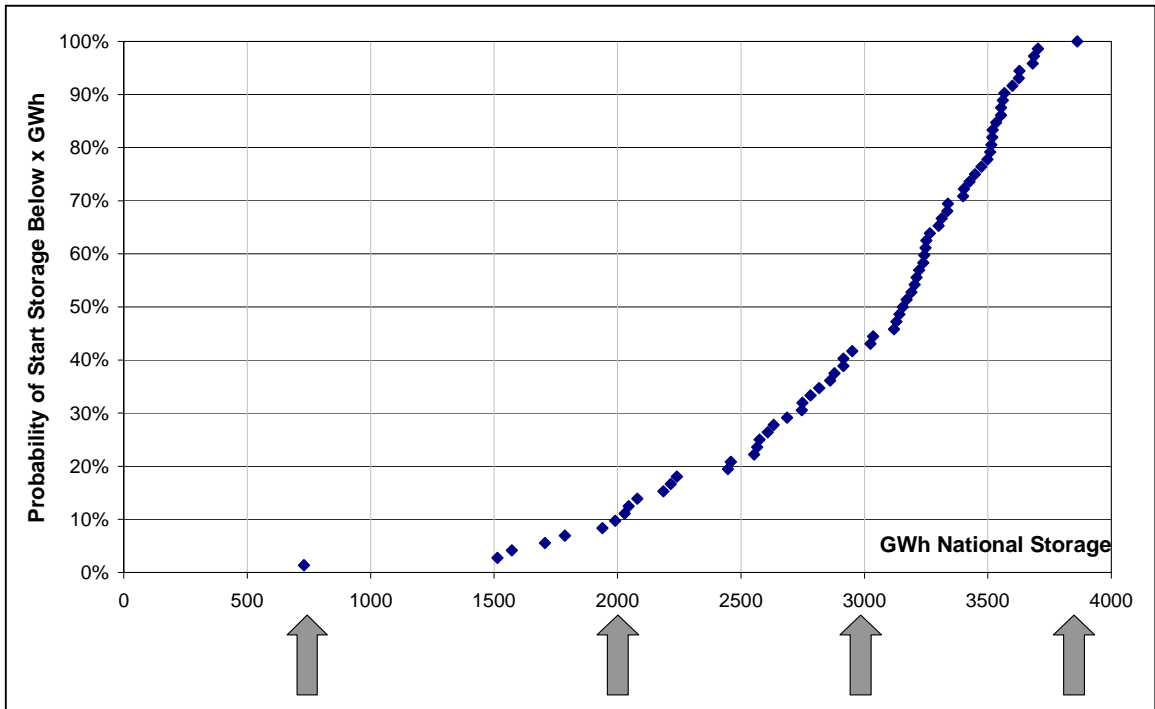
Figure 7 - EMarket Thermal Dispatch with 1932 Inflows



It can be observed that as the storage reduces and approaches the Minzone, New Plymouth starts to run to conserve storage. This continues until some time after the storage returns to above the Minzone. The timing of this and other thermal running appears to be consistent with what Concept believes the incentives of generators would be noting that in addition to commercial incentives, the publication of security of supply information, such as Minzone for example, could be expected to assist. We return to this issue later.

Figure 8 - Distribution of Start Storages for 2005 shows the range of plausible start storages arrived at for 2005 and the likelihood of being at a particular level.

Figure 8 - Distribution of Start Storages for 2005



A representative selection of 2005 start storages was then used as the basis for a series of 2006 simulations using the full 72 years of historical inflow data¹⁶. The arrows at the bottom of the chart indicate the start storage for each of the 2005 runs. Each run was weighted according to the likelihood of its start storage, based on the analysis demonstrated in Figure 8, to establish the likelihood of hydro storage levels being in or near the Minzone in 2005. Figure 9 shows the results of this analysis.

¹⁶ Simulating in this manner means that serial correlation between inflow years has been ignored. That is, modelling assumes that the inflow scenario resulting in the lowest end storage for 2004 is equally likely to be followed by all other inflow sequences. Given more time, it would have been preferable to simulate the market for serial inflow sequences across the two year but it is likely that the approach taken is more conservative than the serial approach.

Figure 9 - Likelihood of Reaching Low Storages in 2005

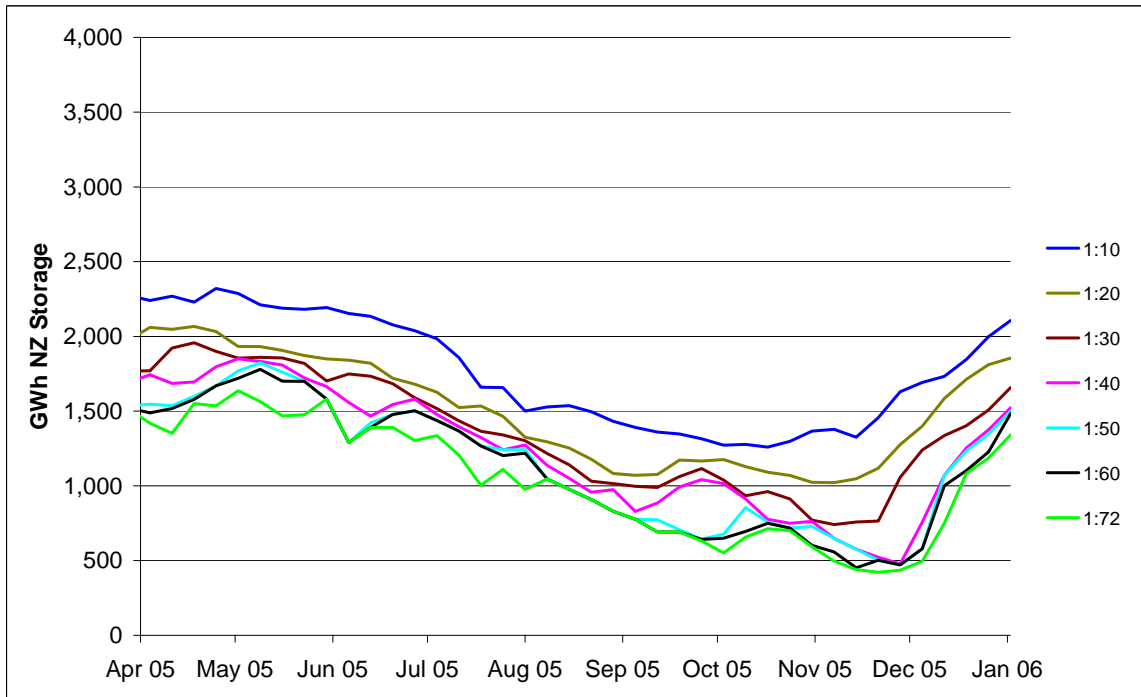


Figure 9 shows a series of storage probability contours over the period April to December 2005 (April is generally regarded as the critical storage month leading into winter). We have expressed the probability associated with each contour as 1:72, 1:60, 1:20 etc recognising that this approach is representative rather than particularly robust statistically¹⁷.

Figure 10 presents the same data in a slightly different way by overlaying the 12 Minzone storage points (Whirinaki included), on the probability contours.

¹⁷ Use of the term *probability* is perhaps misleading because we have assumed each historical sequence has the same probability of recurring and have ignored serial correlation between sequences between years. Nevertheless, without detailed hydrological analysis beyond the scope of this assignment, we believe it is helpful to consider the likelihood of storage reaching a particular level in this way.

Figure 10 - Storage Probabilities Overlaid with Minzone

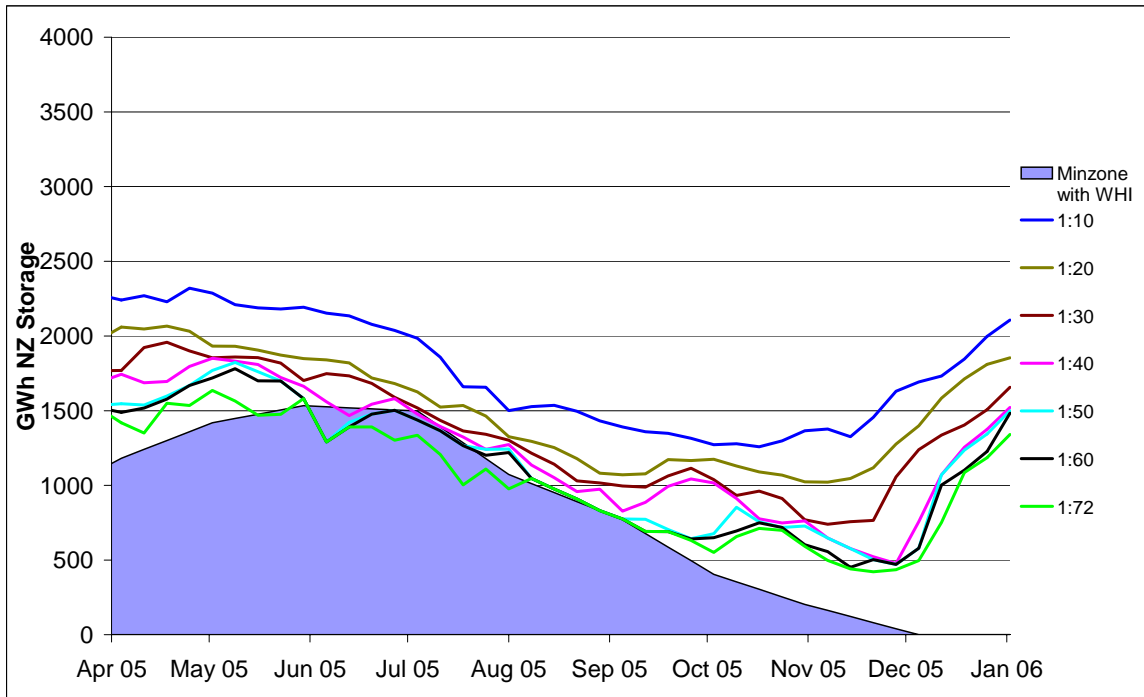


Figure 10 suggests less than a 1 in 30 chance in the worst month (July) of hitting the Minzone, at which point - based on current analysis and assumptions - there is 1:72 chance that the reservoirs will empty if all thermal plant is run to capacity from that point.

The analysis presented here is conservative in a technical sense as we have not modelled any price related demand response and Huntly reserve assumptions are conservative in the Minzone analysis. It is also considered likely that the worst historical inflow sequence up to 12 months ahead would have a return period of greater than 60 years.

However, the analysis is contingent on the 'fully fuelled' assumption holding. It is also contingent on being able to rely on thermal plant being fully committed should the Minzone be reached.

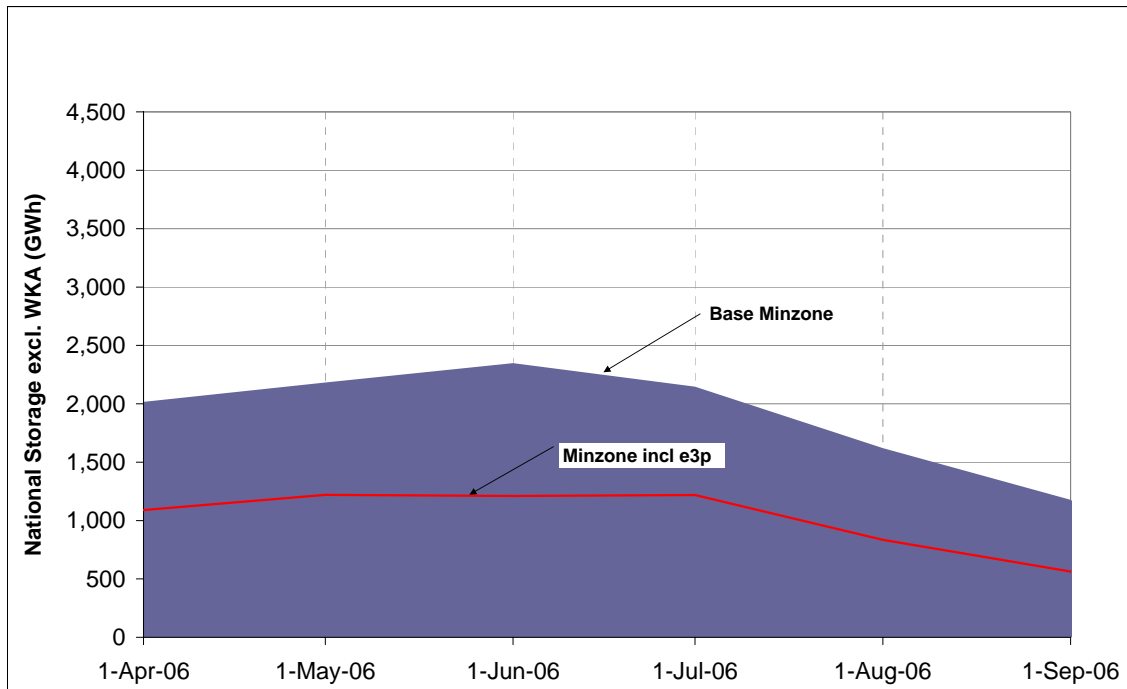
Before considering reserve energy requirements for 2005, we first considered security of supply for 2006.

5.4 2006 Assessment

The requirement for additional reserves could be influenced by the security of supply outlook beyond 2005. As discussed previously, if security of supply risks were perceived to be greater in 2006 (and later years) relative to 2005 then that could have a bearing on any decision to procure reserves now or at least the form of reserves. Longer term requirements would suggest more capital intensive options could be economic. Otherwise shorter term options such as demand side reserves, although potentially complex to administer, might be more attractive. Another consideration is the approach the Electricity Commission may ultimately wish to take to security of supply noting there are a number of options available to it in the longer term. It would presumably wish to retain as much flexibility as practical without compromising the 1 in 60 policy objective in the meantime.

Minzone (capacity runs) were completed for 2006 for two scenarios – one including Genesis’s proposed combined cycle plant based at Huntly (e3p) and one without. Figure 11 shows the results of these runs.

Figure 11 - 2006 Minzone (excl WHI)



Due to time constraints analysis only covered the 6 critical months of autumn and winter

In the without e3p case the Minzone is higher than the comparable Minzone for 2005. This is due to the increase in demand forecast for the year being more than the new supply – with only the 20MW Geothermal plant at Ngawha being included. As noted previously, the potential impact of transmission constraints may at times be understated in the model runs. This may also affect the above e3p analysis. The projected net growth in demand over supply suggests that e3p could be expected to have a significant impact of the minzone in 2006 and later years.

Since completing this analysis we have been advised by the Ministry of Economic Development that it believes Genesis' e3p plant is now unlikely to be commissioned before April 2007. There are a few important points that can still be concluded from Figure 11:

- Any additional reserve energy deemed to be required for 2005 would likely be of at least equal value in 2006 but potentially with significantly diminished value after that given the likely impact of e3p depending on the fuel status of existing thermal plants.
- As modelled, 2006 potentially has more issues relating to system security than 2005 although the Electricity Commission has 18 – 24 months to address these concerns.
- Assuming that e3p is commissioned before the winter of 2007 then the years 2007 and 2008 should result in less system security concerns than 2004 / 6 subject to assumptions about fuel supply. There may of course be scope for older thermal capacity affected by e3p to be contracted to maintain additional fuel stocks as sources of reserve energy.

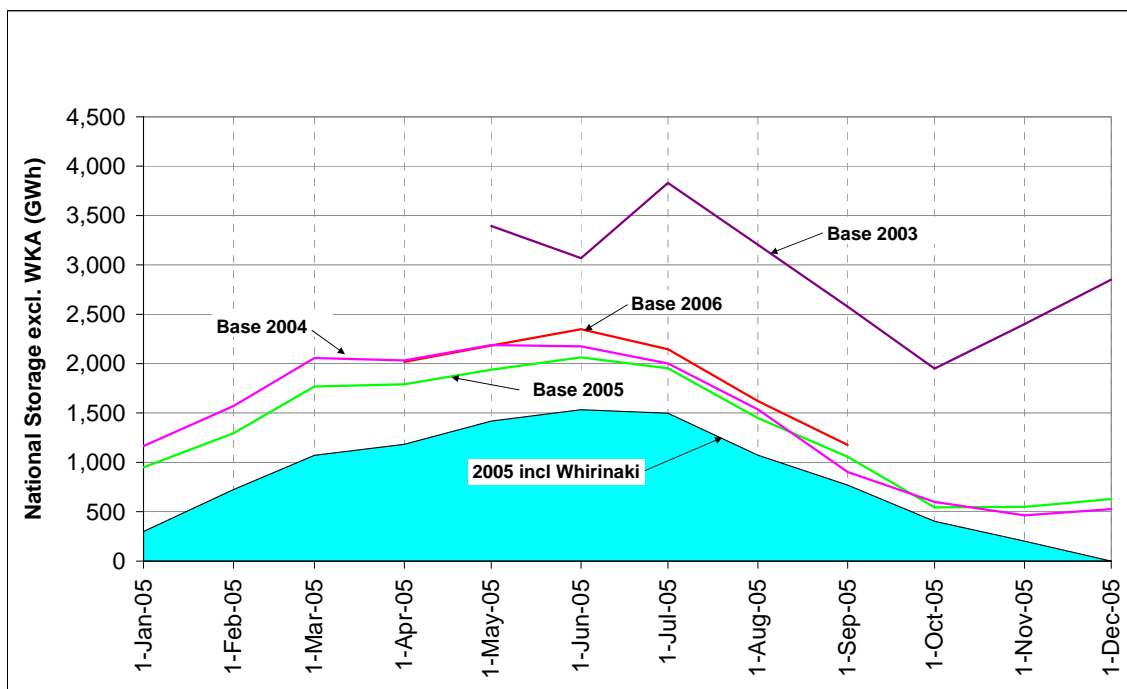
5.5 Historical Perspective

As discussed previously the Electricity Commission will need to be confident that the capacity of the system is sufficient to be able to cope with a 1:60 dry period without the need to call for energy conservation campaigns. To the extent that it is not, procurement of reserve energy contracts to extend security to the 1 in 60 level is an option available to it.

Our analysis suggests that there is a relatively low probability that storage will fall to the 1:72 Minzone level over the next 24 months. Should storage fall to the 1:72 Minzone, assuming full thermal capacity (including Whirinaki) and no demand response, there is only a 1:72 chance that the storage would fall to zero. Should that look likely, assuming other assumptions hold, it would be due to inflows with a return period greater than 60 years (1:72 by the simple estimate). We have ignored any price related demand response which in practice would tend to offset the storage decline.

Given the most recent security concerns in 2003, we believe it is useful to apply the analysis framework presented in this report to 2003 to enable comparison between what happened in 2003 and our assessment of 2005. Acknowledging that the Minzone level of itself is not necessarily a direct indicator of levels of security, Figure 12 shows the Minzones produced in this assignment along with the 2004 Minzone¹⁸ and the 2003 Minzone produced by the Winter 2003 Taskforce in late April 2003¹⁹.

Figure 12 - Comparison of Minzones



The significance of the Ministry of Economic Development's fully fuelled assumption is reflected in the large reduction in Minzone storage between the 2003 and 2004 to 2006 Minzones.

In 2003, the technical supply capacity was clearly limited by fuel supply problems. In contrast to 2003, through industry and Ministry of Economic Development efforts much better information and monitoring now exist. In 2003, lack of information about thermal

¹⁸ Energy Security Assessment: Modelling and Analysis – MED February 2004

¹⁹ The shape of the 2003 Minzone curve reflects significant fuel constraints (with gas supply reductions projected in the last quarter and lead times for procuring uncontracted fuel).

fuel supply constraints in particular meant that storage had fallen below the Minzone level that could have been calculated had the information been available. It is our understanding that release of security projections to the industry in around March 2003 by the Ministry of Economic Development, based on limited information it had been able to ascertain at that time, prompted some market participants to respond immediately to the prospect of supply shortages.

Consideration could be given to undertaking similar analysis to estimate Minzone profiles now for 2001 and even for 1992. However, we believe that would be difficult to do in the case of 2001 and not particularly meaningful in the case of 1992. In 1992 the system was operated to a 1:20 standard and operating to a 1:60 Minzone would clearly have reduced the impact of the water shortage. Information about the thermal fuel supply situation in 2001 would be difficult to establish. More importantly, we believe behavioural incentives are now markedly different for key players. Some generators at that time would have been significantly more exposed to the spot market than now having since acquired significant numbers of customers. While lack of information was clearly an issue in 2003, the response to security concerns was significant.

We believe that the combination of better information flows and significantly greater availability of fuel will have significantly reduced security of supply concerns.

6 Conclusions

Security of supply concerns in 2005 and 2006 should be demonstrably less than in 2003 in terms of technical supply capability in a dry year. Depending on the extent to which transmission constraints impact on Whirinaki, it would appear to be able to make a significant contribution in a very dry year if required as evident from the impact it has on the Minzone.

A key concern we would about security of supply in 2005 is the reliance on thermal stations being fully fuelled. We have been advised by the Ministry of Economic Development that this is a valid assumption based on its discussions with the relevant generators. The Minzone storage indicators presented in this report suggest that 2006 is perhaps of more concern than 2005 based on new supply assumptions for 2006. However, the 2006 security of supply outlook in terms of technical system capacity in a dry year does not appear materially different to that for 2005. The prospect of e3p in 2007 suggests that beyond 2006 the risk reduces significantly noting that there is also a significant lead time now for the Electricity Commission to put appropriate arrangements in place before then.

From a technical dry year supply capability perspective, the Minzone analysis in this report is probably conservative being based on worst case inflows and no spot price related demand response. On the other hand, factors such as the normal demand forecast – noting the use of simple rather than compound growth rates – and

uncertainties about the extent to which at least some hydro storage systems can be drawn down will tend to offset this. We believe that modelling of key transmission constraints warrants closer scrutiny considering the potential contribution of Whirinaki and e3p to technical supply capability compared to earlier studies. On balance, we are comfortable with our conclusions about dry year technical supply capability.

In assessing possible requirements for additional reserve energy for 2005, the key issues would appear to be:

- The extent to which the Electricity Commission will be prepared to rely on the fully fuelled assumptions
- The Electricity Commission's level of comfort that all non hydro generation will be fully committed when a minimum storage threshold is reached
- Whether the Electricity Commission wishes to insure against other risks such as the combination of a dry year and plant failure.

The Ministry of Economic Development has indicated no reason to doubt that adequate fuel supplies exist. We are clearly not in a position to comment on that. Clearly a priority for the Electricity Commission should be to engage with the Ministry and industry to confirm these assumptions. In fact we believe there is a hierarchy of options available to the Commission for dealing with security of supply for 2005, as outlined below.

- *Monitoring*: liaising with the industry and collecting information on fuel supplies, plant availabilities and demand growth, so that the Commission is in a position to monitor security risks and take action, if necessary. We note that the Commission will have certain powers regarding the procurement of information.
- *Clearing house*: assuming the role developed by the Ministry of collating information collected and then promulgating relevant information about security of supply risks. There is evidence that the dissemination of such information by the Ministry has contributed to security risks being significantly reduced.
- *Fuel commitments*: if the Commission wants to go further than the above then it may wish to enter discussions with the key generators to procure more formal commitments on fuel supplies, for example, by way of agreements or memoranda of understanding. There is considerable time available before the winter of 2005 in which to do this.
- *Security Buffer*: if the above is not considered sufficient, the Commission could decide to maintain a higher security threshold than otherwise (through a higher Minzone for example). We note that this potentially carries the risk of spill and interfering with the normal market operation by constraining the range of storage

within which it would operate. One possibility is to adopt a Minzone excluding Whirinaki to provide a buffer against fuel risks or thermal commitment risks. The prospect of a major contingency, perhaps a 1 in 10 year risk, combined with a 1 in 60 inflow sequence would appear to fall well outside the 1 in 60 policy objective. A lesser dry year combined with such an event may have similar impact to a 1 in 60 dry year. Adjusting the security guideline (Minzone) upwards, including reserve energy trigger thresholds, should a major supply failure occur would be prudent.

- *Generator operating commitments:* a further step that the Commission could take would be to consider how to ensure that generators respond appropriately within the normal market to avert the risk of a security situation emerging. We note that the Commission will have a range of options available to it under the proposed EGIB (for example, the possibility of requiring hedges to be offered by generators or requiring generators and retailers/ purchasers to participate in hedge markets). We note there is a reasonable period of time available to the Commission to consider these issues.
- *Tendering for more reserve energy:* a further option is to consider tendering for flexible short term reserve energy options. Demand side arrangements are likely to be well suited to this role although there are likely to be some practical difficulties depending on the nature of the demand reductions tendered. For example, ensuring that offered demand reductions occur in practice, or would not have otherwise occurred. A tender process would also need to be flexible enough to accommodate reserve energy offers with varying cost structures. Should the Commission wish to proceed with a short term procurement tender now, South Island options might be more effective (depending on the time of day) given the risks of transmission constraints limiting the effectiveness of North Island thermal backup. We would note, however, that it would take some time to run a tender and contract for additional reserve energy, and there is limited time within which to do this.

We would suggest that the Commission exhaust the options listed in this section (in order) before making any decision to proceed with a tender for more reserve energy. If a tender were to proceed, then in our view short term flexible options should be preferred.