Concept Consulting Group

Tendering for Reserve Energy: Discussion Paper

prepared for the

Electricity Commission

with assistance from John Culy and Tony Baldwin

November 2004

Advice of Disclaimer

We have used every endeavour to ensure the accuracy and completeness of our report and we are confident in the conclusions we have reached. However, in view of its 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

1.1 Concept Consulting Group[1] has been engaged by the Electricity Commission to advise on how, in accordance with the GPS, it should go about contracting for any reserve energy necessary to ensure security of supply in a 1 in 60 hydrology inflow sequence.

1.2 This report follows two preliminary reports which have each been discussed with the Commission. It has been prepared as a discussion paper for consultation purposes.

1.3 The initial framework and parameters within which the Commission is to manage dry-year security of supply, and contract for reserve energy to achieve a 1 in 60 standard, have been relatively tightly defined by the Government. The recommendations in this report seek to optimise the process of contracting for reserve energy within those parameters.

1.4 The Commission has in progress separate but related projects – one on how to implement the Government's 1 in 60 security policy; another on "emergency provisions" if a dry period is worse than 1 in 60. Concept Consulting is assisting the Commission with these two related work-streams.

1.5 The Commission also has in-train a project on "alternative measures" – to consider longer term options to enhance arrangements and incentives relating to its security of supply objectives.

1.6 In this report, references to:

- the GPS, are to the Government Policy Statement of September 2004.
- the Act, are to the Electricity Amendment Act 2004

Task of consultant

1.7 In its Request for Proposal, the Electricity Commission listed the following tasks the consultant was required to undertake in this project:

[1] Concept has been supported in this work by John Culy, Tony Baldwin and Charles River Associates.

Task 1:	Investigate and recommend how the Commission should go about contracting for reserve energy up to the amount determined as necessary to ensure security of supply in a 1 in 60 year event.
Task 2:	Investigate and recommend the types of reserve energy that are likely to meet the requirements for contributing to reserve capacity.
Task 3:	Investigate and recommend "ring-fencing" and other requirements that would need to be met by all prospective suppliers of reserve energy.
Task 4:	Propose a set of detailed contract arrangements for reserve energy suppliers.
Task 5:	Investigate and recommend a method of tendering for reserve energy that is likely to lead to the lowest cost of energy reserves over the medium term.
Task 6:	Propose a set of detailed arrangements for conducting the reserve energy tender.
Task 7:	Prepare a discussion paper if required, suitable for release by the Commission, which outlines all the issues, discusses the options considered, and outlines the reasons for the recommended reserve energy contracting arrangements.

1.8 Tasks 1 to 3 were considered in a first preliminary report to the Commission in early May. Tasks 4 to 6 were considered in a second preliminary report to the Commission early in July. This discussion paper has been prepared taking into account the Commission's comments and views on the preliminary reports.

1 in 60 security policy development

1.9 This reserve contracting project is closely related to the Security Policy Development project, a separate work-stream on which Concept Consulting is also assisting the Commission.

1.10 The Security Policy project is to develop a mechanism for assessing whether, and (if so) when, the Commission needs to buy reserve energy to meet a 1 in 60 hydrology inflow sequence. The mechanism is likely to be first applied in early 2005 to assess security of supply for 2006 to 2010.

1.11 If the Commission determines it needs to buy reserve energy, the tender and contracting processes developed under this project will be used to procure the required reserve energy.

1.12 The design of tender and contracting processes will also need to provide reserve energy, at particular times of the year, for particular durations, and other specific characteristics implied by the security of supply assessment (including constraints in the transmission network). Dispatch triggers and warning periods are also relevant factors to be taken into account in the tender and contract design.

Timetable

1.13 The timetable for development of this discussion paper and consultation is outlined in Table 1

Table 1: Dates for next steps in this Project

Date	Deliverable	Comment
Nov 2004	Discussion Paper finalised and issued for wider industry and public submissions	The Board agreed to the released of the Discussion Paper for consultation at the 4/5 November Board meeting
Dec 2005 /Jan 2005	Commission considers submissions and seeks SAG advice as appropriate	SAG meets 3 February 2005 to consider submissions.
March 2005	Commission finalises proposals for reserve energy tender and contracting process	

Approach

1.14 Our approach to this assignment has involved:

- Reviewing the role of reserve energy tendering within the Government's overall reserve energy framework to clarify and refine the objectives of the tender;
- Applying our knowledge and experience of the NZ hydro-thermal system and the cost structures of participants in the energy market to identify what types and features of reserve energy (including demand reductions) could provide additional security and hence might be contracted by the Commission;
- Applying the general principles in the GPS in order to interpret the need for "ring-fencing" or other requirements to the various forms of reserve energy to minimise the potential distortion on the "ordinary" market;
- Reviewing the experience of reserve tendering and competitive procurement in other markets;

- Designing a tender process to enhance the level of competition around key variables, with a view to enabling the Commission to select a merit order of reserve energy options with an optimal cost-benefit mix;
- Addressing trade-offs between flexibility in the form of contract permitted to maximise competition and participation versus simplicity, equity and clarity in evaluation. It is also important to recognise the practical, commercial, legal and financial realities facing potential bidders and the Commission, and to incorporate the insights gained from experience elsewhere;
- Distilling the key components of contract "term sheets" for a menu of supply and demand-side reserve energy options, taking into account likely differences in cost-structures, ownership arrangements and operating requirements; and
- Developing a robust methodology for evaluating the costs and benefits of potential competing offers of reserve energy, factoring in significant differences in key variables between supply and demand-side options.

Structure of this report

1.15 This report is structured as outlined in Table 2.

Table 2: Report Structure

	Title	Description
1	Introduction	Description of consultant's role and approach
2	Industry context	Outline of industry structure and features of the market that are relevant to contracting for reserve energy
3	Objectives and Policy Framework	Outline of the policy framework established by the Act and GPS.
4	Interpretation of Policy Parameters	Clarifying the objectives of the GPS
5	International Experience	Outline of international experience with tenders for reserve capacity
6	Tender Process Design	Factors that need to be addressed in the tender design
7	Tender Proposal	Outline of the recommended tender process design
8	Reserve Generation	Features of reserve generation
9	Contracting for Reserve Generation	Issues involved in, and recommended approach to, contracting for reserve generation
10	Demand-side Reserve Energy	Features of demand-side reserve
11	Contracting for Demand-side Reserve Energy	Issues involved in, and recommended approach to, contracting for demand-side reserve energy

	Title	Description
12	Evaluation Issues	Recommended approach to evaluating reserve energy offers.
13	Implementation	Recommended approach to implementing the reserve tender
A1	Review of International Experience	A summary of relevant international experience
A2	Alternative Procurement Process	Alternative approaches to procuring reserves that were considered
A3	Tender Evaluation	Detailed evaluation proposal
A4	Example Term Sheet for Reserve Generation	Detailed Term Sheet for Reserve Generation
A5	Example Term Sheet for Reserve Demand	Detailed Term Sheet for Reserve Demand.
A6	Small customer Reward – Savings Scheme	Outline of a possible small customer reward-savings scheme
A7	Key Terms used in Security of Supply reports	Glossary of key terms

2. Industry Context

2.1 Part F of the Electricity Governance Regulations and Rules ("the rules") requires the Commission to determine the most appropriate grid reliability standards (GRS). Part F describes the purpose of GRS as being to provide a basis for the Commission to publish statements of opportunity, Transpower to prepare grid upgrade plans, and other parties to appraise opportunities for transmission investments and transmission alternatives.[2]

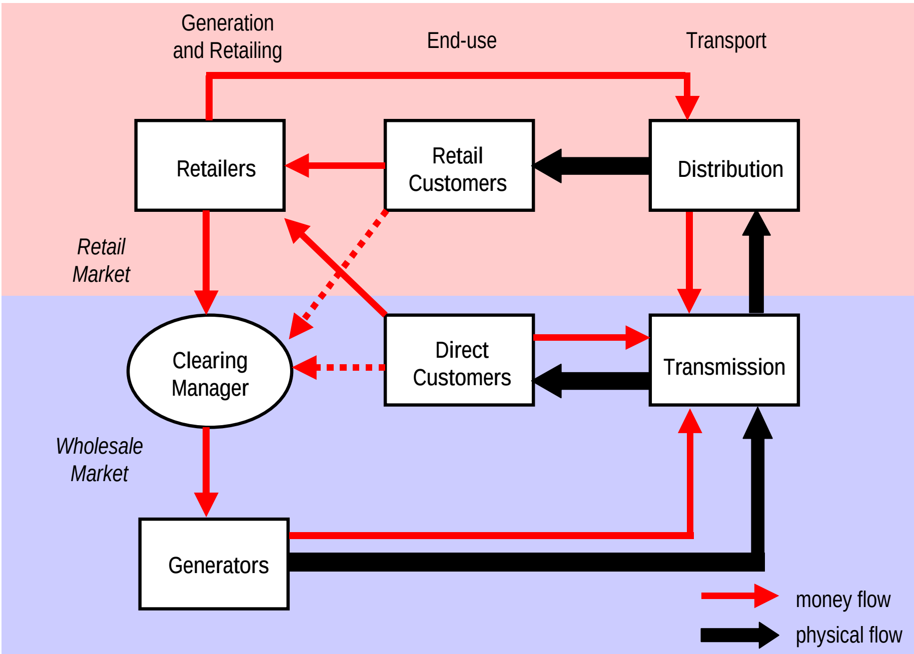
2.2 This section introduces some features of the electricity sector in New Zealand that need to be recognised when designing arrangements for reserve energy.

Industry Structure and Market Operation

2.3 The New Zealand electricity market operates according to a set of rules developed by industry participants over the last ten years, and now operating with the force of regulation under the jurisdiction of the Electricity Commission. The operation of the wholesale market, the retail market, and the contractual relationships, are illustrated in Figure 1.

[2] Rule 4.2 of section III of Part F

Figure 1: New Zealand Electricity Market Structure[3]



Electricity Commission has regulatory oversight of Retail Market, Wholesale Market, Transmission Contracts
Commerce Commission has regulatory oversight of distribution and transmission pricing
Electricity Commission has contracts with service providers for market operation services; Clearing Manager is one of these

2.4 This figure highlights that:

- grid connected generators sell electricity to the clearing manager, at spot prices, through the wholesale market arrangements;
- retail end-use customers typically purchase bundled electricity and lines services through retailers;
- direct end-use customers (grid connected) typically purchase electricity from retailers, and transmission services from Transpower;
- retailers purchase electricity from the clearing manager, at spot prices, for on-sale to end-use customers.

Contracting Arrangements

2.5 How participants in the sector contract for supply, delivery and purchase of electricity has implications for arrangements to contract for reserve energy. It

3 Note that, in the short term, money flows between Purchasers (either Retailers or Direct Customers) and Generators can be two way. However over the longer term they tend to be in the direction indicated in Figure 1

is therefore important to understand the contracting relationships. Particular features include:

- generators selling into the wholesale market (typically grid connected) have exposure to spot prices. When spot prices are high during security constrained periods generators tend to benefit[4];
- many embedded generators (connected into distribution networks) are not exposed to spot prices and therefore do not normally benefit from high sport prices during security constrained periods;
- direct customers (grid connected) often have some exposure to spot prices as a result of the basis upon which they contract with retailers. This means that they have a financial incentive to reduce demand in response to high spot prices during a security constrained period;
- large customers (connected to distribution networks) typically contract with retailers on the basis of fixed-price for variable-volume. They therefore tend to lack financial incentives to reduce demand during periods of high spot prices. Metering arrangements for these customers often include the ability to measure consumption on a half hourly basis;
- small commercial and residential customers typically contract with retailers on the basis of fixed-price for variable-volume. They also lack any financial inventive to reduce demand during periods of high spot prices. Metering arrangements for these customers do not usually include half hourly metering.

Implications for Reserve Energy

2.6 These commercial arrangements reflect quite different financial incentives and exposures for participants in the sector during any security constrained period. These arrangements need to be taken into account when designing the basis upon which the Electricity Commission might contract for reserve energy. In particular, the varying exposures to spot price for different customers need to be taken into account when designing any commercial arrangements with those customers to provide reserve energy.

2.7 These issues are developed further in sections 8 to 11 which deal with contracting arrangements for reserve providers.

4 Assuming that the generator is a net seller, rather than a net purchaser. Generators have tended to ensure that they have maintained a net seller position to avoid the risks associated with being a net purchaser.

3. Objectives and Policy Framework

Security of supply obligations

3.1 Under the Electricity Amendment Act (”the Act”), the Commission is required to achieve a specific outcome where “*risks (including price risks) relating to security of supply are properly and efficiently managed*”[5].

3.2 The Commission has a separate function under the Act in relation to security of supply, which is 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.”[6]

3.3 The scope of security of supply is not expressly circumscribed in the Act[7]. By contrast, the Commission’s role in relation to security of supply under the GPS is focused on the objective of managing a 1 in 60 dry period[8].

3.4 The GPS has three layers of requirements relevant to this project. These are described in the following sections.

General policy in GPS

3.5 There is a clear emphasis in the GPS, both express and implied, that the Commission should, as far as possible, seek to achieve the Government’s policy objectives for electricity by facilitating efficient market mechanisms. Recourse to regulatory powers is proposed only if market-based remedies are unavailable or unsuccessful. In the event of the Commission resorting to regulation, the GPS puts considerable emphasis on designing regulatory measures in a way that minimises distortions to the ”ordinary” market. Indeed, the process for making regulations under the Act has now been made considerably more demanding with a view to ensuring that regulation is a last resort[9].

3.6 Some examples of this core policy emphasis in the GPS include:

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5 Clause 15 of the Act, amending section 172N(2)(b) of the principal Act

6 Clause 16 of the Act, amending section 172O(1)(d) of the principal Act

7 Security of supply has several dimensions including meeting ongoing demand growth, managing extended dry hydro periods, coping with extreme dry sequences or other unexpected supply disruptions, and reliability and capacity adequacy of national grid and distribution lines

8 Paragraph 37, GPS.

9 Clause 9 of the Act, section 172F of the principal Act

- A clear focus on promoting efficient wholesale and retail markets (*paragraphs 76 and 115 GPS*);
- Achieving the specific outcome of minimising barriers to competition in electricity *(paragraph 2(c));*
- The importance placed on innovation *(paragraph 9);*
- The emphasis on efficient risk management – "risks (including price risks) relating to security of supply are properly and efficiently managed" (*paragraph 2(b)*); and
- The value put on efficiency and avoiding market distortions –maximise "static and dynamic efficiency…" (*paragraphs 51 and 65*), take into account the "potential detriments to security of supply and competition in the 'ordinary' market" (*paragraph 53(b))* and "minimise the impacts of the reserve energy scheme on the 'ordinary' market" (*paragraph 56*).

3.7 Avoiding distortions to the *"ordinary"* market is a recurring theme in the GPS. The Government is clearly concerned to ensure that any regulatory measures do not distort market participants' perception of their respective supply risks and their commercial options for managing those risks. Failure by market participants to "take ownership" of their supply risks, and to enter into commercial arrangements to mitigate those risks, will only increase the size of the potential security of supply problem.

3.8 The Government has also made it clear that it expects the Commission to perform its security of supply function largely by means of contractual arrangements with participants rather than by making regulations (although there is provision for regulation[10]).

3.9 The GPS emphasises that "the overriding objective" in relation to the Commission's security of supply role is to "give as much certainty as possible to the market" (paragraph 41, GPS).

Requirements for security of supply

3.10 The GPS is relatively prescriptive in relation to the key components of the security of supply scheme. It requires the Commission to:

- Monitor market supply and demand conditions relative to a published "*minimum hydro zone*" regime;

[10] The Act provides for regulations to require disclosure of information (e.g. hydro lake levels and inflows, plant availability and thermal fuel stockpiles); to require generators to hold reserve fuels and plant capacity, to tender minimum volumes of wholesale contracts or hedges, post buy and sell prices for contracts; and to require buyers of wholesale electricity to have minimum levels of hedge and contract cover. The Act also provides regulation-making powers to secure and use reserve energy, however paragraph 64 of the GPS suggests these regulations would only set out the parameters of the reserve energy contracting regime, with a view to providing some confidence to the market that they are not intended to be readily changed.

- Purchase reserve energy if the Commission determines the market is unlikely to provide sufficient energy over a given duration to meet a 1 in 60 dry period;
- Publish information relating to hydro lake levels, thermal availability, scheduled plant and transmission outages and minimum hydro zones;
- If there is a high risk of shortages, put in place a conservation campaign, which could also trigger use of ripple control of hot water; and
- In the extreme event that blackouts are also required, put in place plans for co-ordinated rolling outages.

3.11 The last two components are to be used in other security of supply situations, not just a dry period worse than 1 in 60[11]. These two emergency responses are to be activated by a second-level trigger (set by the Commission) to signal a significant probability of a worse than 1 in 60 dry year event.[12]

3.12 Paragraphs 65 to 67 of the GPS require the reserve energy regime to be reviewed at the end of 2006. Alternative mechanisms may be recommended for managing dry year risks.

Specific parameters of reserve energy regime

3.13 Purchasing reserve energy is to be a primary mechanism for the Commission in meeting its obligations in relation to security of supply[13]. The GPS prescribes a range of quite specific parameters for the Commission's reserve energy regime, in particular:

- Reserve energy may include generation and demand response. However, in relation to demand response it must be practicable and the Commission must be confident that the demand reduction is additional to normal demand-side responses to higher prices *(paragraphs 47 and 54, GPS)*
- The full output of contracted reserve energy may not exceed 1200 GWh over any four month period, taking into account transmission constraints and other relevant factors *(paragraph 49, GPS)*. The Government has already contracted for an additional 155MW from the new Whirinaki plant (450GWh over a 4 month period) *(paragraph 58, GPS)*, so the maximum additional reserve it can procure is 750 GWh over a 4 month period

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11 Under paragraph 72 of the GPS, conservation campaigns are to be used where there is a *"high risk of shortages"*. A worse than 1 in 60 dry period is given as an example, which implies that these measures may also be used in other (unspecified) *"high risk"* situations. [Note that the Act refers to *"material risk"*]. Paragraph 73 of the GPS states that ripple control may be used for *"major and unexpected plant or transmission line outages",* but does not give examples of other security situations in which a conservation campaign may be used.

12 Paragraph 45, GPS

13 Paragraph 47, GPS

- The Commission is to forecast three to five years out in assessing its possible reserve energy needs *(paragraph 40, GPS)*
- Contracting for reserve energy is to maximise "static and dynamic efficiency" (paragraph 51, GPS)
- Impacts on the *"ordinary"* market are to be minimised *(paragraph 56, GPS)*, particularly impacts on incentives for market participants to construct new capacity, enter into hedge and other contracts and invest in demand-side management *(paragraphs 50 and 56, GPS)*
- To minimise impacts on the *"ordinary market*", reserve energy is to be initially tightly *"ring-fenced*". This means that reserve energy may only be used for security of supply objectives, with a limited exception for distributed generation mentioned below *(paragraph 56, GPS)*
- Distributed generation contracted for reserve energy may be used for network load management. However, the Commission is to carefully define operating parameters for this exception, including considering a cap on MW capacity and on the hours of network load management per year *(paragraph 56, GPS)*
- Reserve energy is to be available to "help cope with other unexpected contingencies, such as serious grid, plant or fuel supply disruptions" (*paragraph 47, GPS*)
- There is a preference for short term contracts *(paragraph 51, GPS)*
- Reserve energy from generation should primarily have low fixed cost and high variable cost, including plant that would otherwise have been mothballed or retired, rather than base-load plant *(paragraph 52, GPS)*
- Reserve energy contracts should provide for fixed payments to cover availability and variable payments when reserve energy is called by the Commission *(paragraph 57, GPS)*
- In deciding whether to contract with existing plant, the Commission is to take into account the possible benefits of lower cost, but also the potential detriments to security of supply and competition in the *"ordinary"* market before replacement generation is commissioned *(paragraph 53, GPS)*
- The Commission is only to buy energy, not plant *(paragraph 59, GPS)*
- Reserve energy is to be dispatched at 20c/kWh or the contracted variable payment, which ever is the higher, unless the Minzone is breached in which case it may be dispatched at a lower price to preserve hydro storage *(paragraphs 60 and 61, GPS),* and
- Any spot price revenue from reserve energy sales are to go to the Commission to contribute to the levy fund *(paragraph 57, GPS)*
- The Commission's net costs relating to reserve energy (operating and capital payments less any revenue received from the sale of reserve

energy) will be recovered by a levy on all consumers *(paragraphs 62 and 63, GPS)*

- The Commission is to publish its processes for procuring reserve energy including its processes for assessing competing offers of reserve energy *(paragraph 55, GPS)*
- The Commission is also to put in place protocols to manage potential conflicts between its role as a participant in the market (as a contractor for reserve energy) and as a regulator *(paragraph 46, GPS)*

3.14 These parameters provide a specific formulation for the reserve energy scheme and are drawn on heavily in the balance of this paper.

Regulatory and contractual issues

3.15 Under the Electricity Amendment Act it is clear that the reserve energy regime is to be put in place using contracts.

3.16 This emphasis is now evident from several statutory references, including:

- The proposed definition of reserve energy: "energy that is secured by **contract** (including by contracting for demand-side savings) by, or on behalf of, the Commission for the purpose of ensuring security of supply" (emphasis added)[14];
- The description of the Commission's functions relating to security of supply, now amended to read: *"use reasonable endeavours to ensure security of supply (including **contracting** for reserve energy)"*[15] (emphasis added);
- The clear direction in relation to the Commission implementing its functions: "The Commission's functions may be carried out by…entering into joint venture or **contractual** arrangement in respect of reserve energy…"[16] (emphasis added); and
- The GPS, which requires the Commission *"to contract for reserve energy"*[17].

3.17 However, the high level operational parameters of the reserve energy regime are also required by paragraph 64 of the GPS to be set out in regulations. The rationale for setting out these features in regulations is to reduce the risk of market participants' concerns that the "boundaries" of the regime to are likely to "creep" over time, causing a greater distortion in the "ordinary" market.

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14 Clause 4(b) of the Act, definition to be included in the principal Act

15 Clause 16 of the Act, section 172O(1)(d) of the principal Act

16 Clause 16 of the Act, section 172O(2) of the principal Act

17 GPS, paragraph 47

3.18 The regulations will need to be designed, drafted, consulted upon and implemented before the Commission initiates the first formal tender process. The regulation-making work stream is outside the scope of this project, but included here for completeness.

4. Interpretation of Policy Parameters

4.1 The GPS sets out a range of reasonably prescriptive parameters within which the Commission is required to operate the Government's security of supply policies. Contracting for reserve energy is *"a primary mechanism"* [18] for the Commission in ensuring security of supply in a 1 in 60 dry year. However, the GPS lacks detail in some areas and requires the Electricity Commission to make judgements of interpretation in relation to several policy parameters.

4.2 This section examines these areas and recommends an approach the Electricity Commission could take on each issue.

Constraint on Reserve Energy Purchases

4.3 The limit of 1200 GWh over any four month period raises a number of questions of interpretation:

- is the use of reserve energy intended to be focussed only within a chosen 4 months period, or is it available for use over an extended period if necessary?
- is the actual use of reserves (as opposed to capability) intended to be limited to 1200 GWh?
- does the 1200GWh limit over four months limit the maximum capability to 416MW[19], or should it be possible to procure 1200GWh that is deliverable over a very short time frame (for example 2000MW could deliver 1200GWh over 25 days)?
- if reserves become unusable (for example if transmission constraints are expected to limit the use of Whirinaki) should that be taken into account in assessing the additional reserves to be purchased?

4.4 The GPS makes it clear that the 1200GWh limit is intended to provide market participants with some surety about the maximum extent of the Electricity Commission's interventions, in order to minimise the extent to which the reserve energy strategy impacts on investing and other commercial market arrangements.

4.5 When considering what this implies for the constraints on the volume of reserves to be purchased it is useful to consider the different characteristics of generation and demand reserves. In particular:

- Generation reserves are likely to be relatively expensive to secure as an option (i.e. higher availability fee) but relatively cheap to call upon when

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[18] Paragraph 47, GPS

[19] A 416MW plant, run continuously over four months, would produce 1200 GWh

required (i.e. cheaper than many demand-side options). Generation reserves are therefore likely to be suited to continuous operation over several months during a security constrained period;

- Many demand reserves are likely to be relatively cheap to secure as an option (i.e. low availability fee) but expensive to call upon when required (because non-supply costs are high for many customers). Demand reserves may therefore be more suited to "just in time" operation towards the end of a security constrained period.

4.6 These characteristics suggest that generation reserves are likely to be contracted as base-load MW capable of operating over a sustained period, while demand reserves are likely to be contracted as GWh savings targets potentially focused into a few weeks. The GPS concerns about retaining incentives for investment appear to relate more to the former than the latter, because of concerns about minimising the impacts on the market for base-load generation.

4.7 Reserve offers with a low availability fee and high variable cost (likely from demand side) might be attractive in an overall cost minimising sense if it is possible to schedule the 1200 GWh within a very short period (say over a month). This is because it would be possible to defer scheduling of the reserve until much later without compromising security of supply and potentially avoid unnecessary use of reserves.

4.8 Some reserves will have a theoretical capability that is greater than their practical capability. This is particularly the case with reserves in constrained regions. For example, it is possible that transmission constraints could limit the extent to which Whirinaki is able to contribute reserve energy under some circumstances. In these cases, it is the effective contribution to security that should be important.

4.9 The GPS requirement to limit reserve energy to "1200 GWh in any four month period" implies a degree of flexibility to schedule reserve energy beyond 1200 GWh, if security is constrained over an extended period of more than four months. However, the desire to minimise the impact on ordinary investment suggests that the Commission should maintain a tight limit, while recognising the need for some flexibility.

It is recommended that the Electricity Commission adopt the following policy to interpret the GPS requirement to limit reserve energy to no more than 1200 GWh:

- reserve energy procurement should be limited to 1200 GWh over any four month period without any limit on MW capability;
- once procured, reserve energy should be available for

dispatch at any time within the full window during which security concerns could arise (subject, of course, to the particular constraints associated with individual reserves) and for longer than four months if necessary;

- reserve energy should be available for dispatch in excess of 1200 GWh in any one year only if the period of security concern[20] extends for longer than four months;
- the effective contribution from reserve energy should be considered when assessing the contribution to the 1200GWh limit.

Contract Duration

4.10 The Electricity Commission is required to forecast 3 to 5 years out, identify any security problems over that timeframe, and contract reserve energy to meet any shortfalls, year by year. This could be interpreted as constraining the Electricity Commission from contracting for reserve beyond the 5 year time frame. This might mean a contract term of only 3–4 years given the lead time for running a tender and commissioning plant.

4.11 If this were to be the case, it would tend to work against generation reserves based on new plant. Such plants are likely to prefer long term availability payments (10 years plus) in order to make them commercially viable. It does not appear to be Government's intention to restrict generation reserves in this way. The recent contract for the provision of reserve plant at Whirinaki tends to confirm this.

4.12 Although there is no intention to restrict contracts to five years, the uncertainty about the need for reserve energy beyond the 3 to 5 year window should result in more value associated with near-term reserve relative to longer term reserve. This is best handled through the evaluation process.

It is recommended that the Electricity Commission forecast security of supply for at least five years and be prepared to contract for reserves that extend beyond five years.

Cost Minimisation Objective

4.13 The GPS objective to minimise the long term costs of the reserve energy scheme has now been amended to provide an overall objective to "maximise static and dynamic efficiency", while taking into account the additional flexibility provided by short-term contracts.

[20] In other words the period during which storage remains below the minimum hydro zone.

4.14 This change appears to stem from a concern that implementation of the reserve energy scheme could, over time, lead to distortions in the market that are damaging to the national benefit. The key here appears to be achieving the correct trade-off between the costs of shortages and the costs of distorting the market. This trade-off is best made when establishing the security policy and assessing the need for reserve energy. It therefore seems reasonable to assume that the objective of minimising the cost to the economy need not be extended into the procurement phase. The test for the tender also needs to be simple to evaluate and relatively transparent to potential providers. We have therefore adopted the assumption that, when contracting for reserve energy, the Commission will attempt to minimise the present value of the net costs of procuring and utilising the reserve to meet the identified "need", taking into account the uncertainty in the "need" for additional reserve beyond the lead time of new plant.

> It is recommended that, when contracting for reserve energy, the Electricity Commission adopt an objective of minimising the present value net cost to the Commission of procuring and utilising the reserve necessary to meet the security standard.

Minimise Impacts on "Ordinary" Market

4.15 The requirement to minimise the impacts on the "ordinary" market appears to be closely linked to the requirement to initially adopt a tight ring-fence, and driven by concern that the security policy could undermine investment in generation and demand-side initiatives.

4.16 The ring-fencing of reserves appears to address these concerns in two ways:

- it seeks to avoid contracting for reserve from projects with other purposes that may have proceeded anyway;
- it seeks to avoid reserve energy suppliers competing in the ordinary market and potentially displacing other initiatives.

4.17 By tightly ring-fencing reserve generation it is possible to ensure that it only runs in response to security concerns. However, ring-fencing demand reserves is a more complex exercise, and it is not clear that a tight ring-fence on demand reserves would provide the desired outcome. For example, a tight ring-fence might imply that the physical systems that provide the capability to interrupt load are to have no other use, or that an interruption to load can only ever be through the dispatch of reserve energy. Such restrictions would be impractical to enforce and it is not clear that the outcomes of enforcement would be appropriate or efficient.

4.18 The purpose of contracting for reserve energy is to provide security that is additional to that provided by the ordinary market. The need for reserve energy is the shortfall between what is needed to meet the security standard and what the "ordinary" market will provide. Eligible offers for reserve should therefore be from demand reductions that have not already been assumed in the security needs assessment. That is, any eligible demand reserves need to be clearly identified as additional.

4.19 In the ordinary market, interruptible loads contribute to dry year security when they respond to rising spot prices. We understand that reserve energy needs are being assessed assuming only market responses that can be reliably counted on. In principle, this sets the threshold of what security is additional and what offers could be eligible. These issues are addressed further in section 10.

> It is recommended that the Electricity Commission adopt the following policy to interpret the GPS requirement to minimise impacts on the ordinary market:
>
> - confirm that reserve generation should be tightly ring-fenced so that it does not run other than for security reasons[21];
> - acknowledge that more flexibility may be required when assessing eligibility of demand-side reserves.

Preference for Some Offers

4.20 The requirement to demonstrate a preference for low fixed cost, high variable cost offers reflects an expectation that this is likely to:

- minimise the cost of reserves by avoiding high availability fees and utilising reserve generation relatively infrequently; and
- minimise the impact on the ordinary market by avoiding contracting with generation capable of competing in the market at prices less than 20¢/kWh.

4.21 An objective to minimise the distortion to the ordinary market is likely to lead to a preference for low fixed cost, high variable cost reserve offers. The question for the Electricity Commission is whether the preference outlined in the GPS should result in some particular penalty function applied during the evaluation of offers. A case for this could be built around an expectation that contracting with reserve demand at high variable cost might be less distortionary than contracting with reserve generation at lower costs. However, it is difficult to see how such a penalty could be applied objectively. Further, the process of evaluating offers to minimise net cost will tend to favour offers with low fixed cost and high variable cost. This is because the probability of using reserves is low (i.e. less than 1 in 60). Offers with a low fixed (certain to be incurred)

21 except as outlined in section 4

cost combined with a high variable (low probability of being incurred) are likely to be favoured over offers with a high fixed (certain to be incurred) cost.

> It is recommended that the Electricity Commission agree that the process of evaluating offers to minimise net cost will tend to favour offers with low fixed cost and high variable cost, and that this should satisfy the expectation set out in the GPS.

Supply Contingencies

4.22 The requirement for reserve energy to be available to *"help cope with other unexpected supply contingencies, such as serious grid, plant or fuel supply disruptions"* has been recently added to the GPS. This new element requires some clarification.

4.23 The issue is, what level of influence *"other unexpected contingencies"* should have in the Commission's reserve energy procurement decisions? Is it a primary stand-alone purpose, or is it incidental to managing *"dry period"* risks?

4.24 If it is incidental, the Commission's reserve energy portfolio would be assembled to achieve a single purpose: managing "dry period" risk. "Other unexpected contingencies" would not have a material influence on the security "needs assessment", tender design or evaluation processes. "Dry period" management would be the primary driver in selecting reserve energy types, quantities and location. Once *in place*, reserve energy could be used for "other unexpected contingencies" to the extent it could make a positive contribution.

4.25 A second interpretation is that, while use of reserve energy for "other unexpected contingencies" may be an incidental purpose, it should be a discriminating factor in choosing between two otherwise "equal" reserve energy options competing for selection by the Commission.

4.26 A third interpretation is that use of reserve energy for "other unexpected contingencies" is a primary stand-alone purpose. If this is so, the tender and evaluation processes would need to be designed to achieve two objectives of equal ranking. This is likely to have a direct impact on the composition of the Commission's reserve energy portfolio.

4.27 It is our understanding that the second interpretation is consistent with the intention of the GPS and we have therefore assumed this for the purpose of this report.

> It is recommended that the Electricity Commission agree that the use of reserve energy for contingencies is an incidental purpose that should be treated as a discriminating factor in choosing between equal options.

Review of Approach

4.28 The GPS outlines a clear strategy for implementing a more secure supply of electricity based upon a 1 in 60 security standard and contracting for reserve energy supplies. It is clear that Government intends that this approach be adopted in the short-term, and at least until 2006.

4.29 However, the GPS also outlines a requirement for the Electricity Commission to review the efficiency and effectiveness of the reserve energy policy, and to consider a range of alternative measures that might provide a better outcome.

4.30 The review is outside the scope of this work stream. Our approach is therefore to consider means of implementing a tender for reserve energy within the framework outlined in the GPS. Any improvements to these arrangements are to be the subject of the review exercise.

Summary

4.31 For ease of reference, our recommendations in relation to the specific GPS parameters are set out below:

- Reserve energy procurement should be limited to 1200 GWh over any four month period without any limit on MW capability;
- Once procured, reserve energy should be available for dispatch at any time within the full window during which security concerns could arise (subject, of course, to the particular constraints associated with individual reserves);
- Reserve energy should be available for dispatch in excess of 1200 GWh in any one year only if the period of security concern[22] extends for longer than four months;
- Electricity Commission should forecast security of supply for at least five years and be prepared to contract for reserves that extend beyond five years;
- When contracting for reserve energy, the Electricity Commission should adopt an objective of minimising the present value net cost to the Commission of procuring and utilising the reserve necessary to meet the security standard.

[22] In other words the period during which storage remains below the minimum hydro zone.

- Reserve generation should be tightly ring-fenced so that it does not run other than for security reasons[23].
- Flexibility may be required when assessing eligibility of demand-side reserves.
- The process of evaluating offers to minimise net cost will tend to favour offers with low fixed cost and high variable cost, and that this should satisfy the expectation set out in the GPS.
- The use of reserve energy for contingencies is an incidental purpose that should be treated as a discriminating factor in choosing between otherwise equal options

23 Except as in relation to distributed generation used for distribution network load management (paragraph 56, GPS), and to help cope with other unexpected supply contingencies (paragraph 47, GPS)

5. International Experience

Introduction

5.1 Reserve energy schemes are used in a number of overseas electricity markets. However because of differences in the generation mix and direction of regulatory policy, reserve energy schemes have tended to develop in different directions and with different objectives. The result is that the term "reserve energy" can have different meanings in different markets.

5.2 In the NZ market, hydro inflow variability is a major security of supply issue. In most other markets, security of supply concerns centre on whether there is sufficient capacity to meet demand during peak demand periods. Without the issue of hydro variability, reserve energy needs tend to be more predictable: additional reserve energy is needed as demand increases; less is required as new generation is added to the system.

5.3 The slow moving and predictable nature of reserve energy needs in most overseas markets tends to allow those markets to delay committing to the reserve energy until close to when it is needed, and to contract for short time frames.

5.4 In most markets, a regulator sets the required level of reserve energy and the mechanism by which the need is to be met. Where tender processes are used, we have examined these models in more detail (in Appendix 1) to see if there are lessons that can be incorporated into our approach to tendering.

Markets Considered

5.5 The following markets/tender processes have been considered in some detail:

- NEMMCO – Victoria / Sth Australia 2002
- National Grid, UK 2003
- Northern Ireland Regulator 2003
- Western Australia 2002
- Townsville Power Station, Queensland 2001

5.6 Of these, the first two probably have most relevance to our situation in that they tend to focus on short term capacity problems and that they allow for both demand-side and supply-side reserve energy options. However, neither NEMMCO, nor the UK has the hydro variability problem that is a feature of the New Zealand market and potentially results in a large transient disparity between supply and demand.

Application of Overseas Experience to New Zealand

5.7 Key points that can be taken from the overseas experience are:

- The favoured means of keeping reserve energy costs as low as possible and ensuring that interference with the normal market is minimised, is to keep the timeframe between tendering for reserve energy and the requirement for reserve energy as short as possible, and to define a short duration of need.
- Applying short timeframes between tendering for reserve energy and the requirement for the reserve energy, has not meant that offers of reserve energy have been limited. Both NEMMCO and the National Grid achieved useful quantities of reserve energy offered within short timeframes.
- Offerers have been encouraged to offer reserve products to a common template so they could be readily compared on a similar basis.
- There has been a strong emphasis on the ability of the offerer to deliver the reserve energy. This emphasis has been critical in the evaluation phase of tender processes.
- In some cases the evaluation criteria have been clear to the prospective tenderers, while in other cases this has not been the case. In either case it is important that the organisation running the process is clear on the criteria at the outset in order to ensure that the relevant data is collected through the tender process, and that the evaluation can be readily made.
- Where the reserve needs are well defined and the types of reserve energy available are well known, then a relatively simple tender process can be adopted.

5.8 We have taken all these points into account when considering the most appropriate framework for New Zealand.

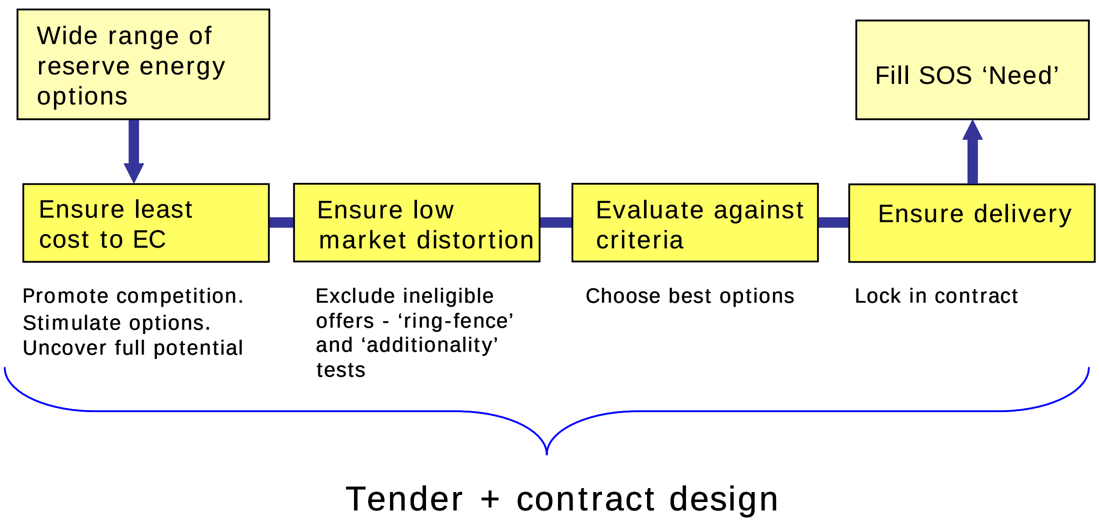
6. Tender Process Design

6.1 The primary focus of this report is on the design of a tender and contracting process to meet the objectives and parameters set out earlier in this report.

Objective

6.2 Put simply, the aim of the tender and contracting process is to procure reserve energy required by the Commission at least cost to the Commission and in a manner that minimises distortion to the "ordinary" market. This is summarised in Figure 2.

Figure 2 Tender Design



6.3 Several factors need to be taken into account in designing a tender and contracting process to achieve this objective, in particular:

- The embryonic and (at this stage) uncertain nature of the market for reserve energy, particularly the range of possible reserve energy options
- The difficulty of comparing the costs and benefits of dissimilar reserve energy options
- The need for flexibility in responding to different "dry year" scenarios
- The duration between committing to purchase reserve energy and the risk period for which it may be required; and
- The practicability and impact of the Government's "ring-fencing" and "additionality" requirements.

6.4 These factors are considered further in this section, except for "ring-fencing" and "additionality" requirements, which have implications for contracting that are addressed in later sections of this report.

Range of reserve energy options

6.5 The market for reserve energy is new and relatively unexplored. Many market participants are likely to be unaware of opportunities, particularly on the demand-side. Some market participants will be aware of opportunities that we have overlooked. The full potential of the reserve energy market is therefore comparatively unknown. However, initial investigations and results of international experience have revealed a number of alternatives.

6.6 Potential sources of reserve energy are summarised in Table 3:

Table 3 - Potential Sources of Reserve Energy

Supply-side options	Demand-side options
• Existing diesel plant built into supply chain (e.g. within distribution network) • New peak station (e.g. Whirinaki) • Recommission mothballed plant (e.g. Marsden B) • Increase fuel stocks • Transmission lines upgrade • Short term rental generation	• Interruptible load contract with spot market end-consumer • Demand-side exchange with time-of-use tariff customers • Buy-back scheme run by retailer with domestic customers • Existing back-up generation downstream of end-users metering

6.7 All options will need to be evaluated against the ring fencing and additionality criteria. Several of the potential sources identified in Table 3 are likely to be eliminated by these criteria.

6.8 The Commission is likely to achieve a lower cost menu of options by promoting greater awareness of reserve energy opportunities among market participants and enhancing competitive participation in the tendering process.

6.9 The challenge underlying this project is to "uncover" the potential and "capture" the options that most efficiently meet the Commission's reserve energy needs for a given period, consistent within the Government's policy requirements.

Problem of comparisons

6.10 A corollary of encouraging a wider and deeper range of potential reserve energy offers is an increase in the complexity of comparing costs and benefits across competing options.

6.11 For example, some demand-side options have relatively high variable costs, low fixed costs, shorter activation lead-times, shorter set-up times, less certainty of delivery and shorter periods of availability. By contrast, some supply-side options have relatively low variable costs, high fixed costs, longer activation lead-times, longer set-up times, more certainty of delivery and longer availability.

6.12 Several key variables that are relevant to a supply-side offer may not feature in demand-side offers. Even within offers of the same energy type, costs and risks may be structured in highly idiosyncratic and individualised ways, making comparisons across competing offers extremely difficult.

6.13 These factors highlight that the Commission is likely to be required to choose reserve energy products from a very diverse range of offers with fundamentally different characteristics. For this reason this report does not consider auction style tender processes with market clearing prices.

6.14 Accommodating the likely diversity of product offers in a tender process gives rise to three key risks:

- **Complex tender and contract documentation:** Legal documents covering all potential offers within a single tender are likely to be longer and more complex. They will be multi-layered with large portions having limited relevance to many potential participants;
- **Less concentrated competition on key discriminating variables**: If the tender rules are more flexible, offerors may seek to differentiate their proposal on non-standard variables (factors other than price), with the result that competition on key criteria (costs and prices) is weaker; and
- **Uncertainty and complexity of evaluation:** Competing offers of different energy types, each structured in an idiosyncratic manner, are very hard to compare. It requires a process for translating disparate costs and benefits to a common base. The methodology is complex and may cause confusion among interested parties.

6.15 Without careful design, these three factors could:

- Discourage offers from some potential tender participants. This would reduce competition and diversity of reserve energy options, which would (in turn) lower the probability of the Commission achieving its least cost objective;

- Increase transaction costs for participants and the Commission. This would arise from more complex and less certain tender and contracting arrangements;
- Reduce flexibility in tender timing, which could also lead to higher costs to the Commission; and
- Lead to excessive subjectivity in administering tender rules, particularly in relation to compliance and evaluation. This could raise concerns in relation to perceptions of fairness and bias, and potentially lead to poor outcomes.

6.16 To mitigate these risks, while still encouraging participation from a wide range of reserve energy options, some degree of standardisation and prescription may be appropriate, particularly in relation to portfolio mix (type, quantity and location), tender rules, evaluation methodology and contract documentation. A balance is required. Too much prescription could preclude less conventional but lower cost options. Too little prescription is likely to discourage participation, weakening competition and increasing costs for the Commission. Striking the right balance is therefore important.

Need for flexibility

6.17 Under the GPS, reserve energy is to be purchased to ensure security of supply in a 1 in 60 ”dry period”. It is also to be available *“to help cope with other unexpected supply contingencies, such as serious grid, plant or fuel supply disruptions”* (*paragraph 47 of the GPS*).

6.18 Inherent in managing hydrology risk is the core problem of not knowing where or when a dry event will occur, how long it will last, or its impact on supply. For example, a dry period may occur late in the winter and require only a short burst of additional peaking capacity to bridge the gap. On the other hand, it may occur early in the winter with the prospect of hydro storage levels falling well below the Minzone, requiring a deep and sustained level of reserve energy (DSM and generation) to avoid outages.

6.19 In general, other unexpected supply contingencies such as grid, plant and fuel disruptions tend to be of shorter duration, but require more immediate reserve energy responses. The need may also be specific to particular locations on the grid.

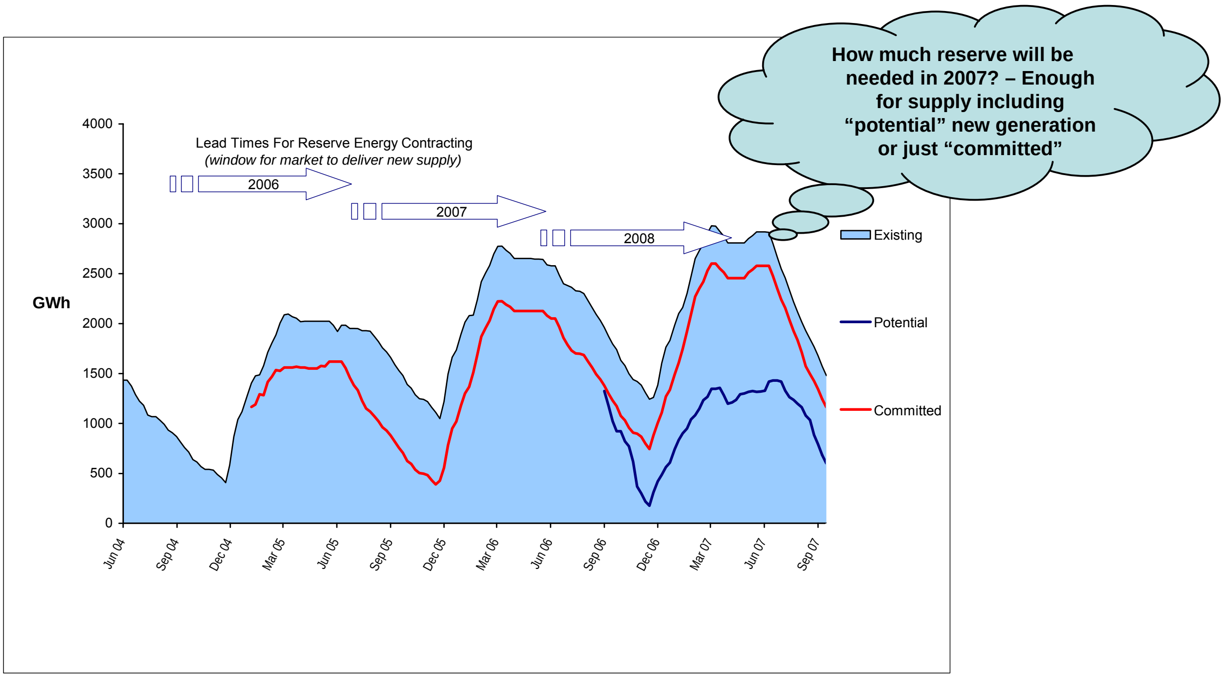
6.20 Different types of reserve energy have different characteristics. Some can be dispatched at short notice but sustained for short durations. Others require longer notice, but can be delivered with more certainty for longer periods. Grid constraints can have a material impact on the utility of a particular reserve energy option. The relative flexibility of competing offers is therefore an important factor.

6.21 A portfolio of reserve energy sources is likely to be required offering sufficient flexibility to respond to a range of dry period security scenarios. Meeting other unexpected supply cost is seen as a secondary objective. Developing an optimal portfolio is a key objective in the tender and contracting process.

Tender timing

6.22 Projecting future electricity supply and demand is inherently uncertain. This uncertainty increases as the projection period increases. Relatively small changes in some assumptions can have a significant impact on expected security margins and movements of the Minzone. This is illustrated in Figure 3.

Figure 3: Illustration Minzone from Needs Assessment



6.23 This highlights a key risk for the Commission in buying reserve energy: the longer the duration between a decision to procure and the security period for which the reserve energy is projected to be required, the greater the risk of redundancy and distortion.

6.24 Redundancy arises if reserve energy is purchased or committed but not required. Apart from changes in hydrology, this may occur if actual supply is greater than forecast, or if actual demand is less than forecast.

6.25 Distortions will occur if the Commission prematurely takes responsibility for a security risk which would otherwise have been adequately addressed by market participants. Relaxing ring-fencing rules relating to reserve energy (merging it in with "ordinary" supply) may also distort the market. Pressure to relax ring-fencing rules is likely to increase significantly if reserve energy turns out to be redundant.

6.26 These risks of redundancy and distortion can be reduced by shortening the period between reserve energy procurement and expected use.

6.27 A shorter lead-time may also enable greater accuracy by the Commission in deciding the optimal quantity, location and type of reserve energy to be purchased. It should also increase the range of potential demand-side options, as many consumers tend not to be in a position to contract for load reductions more than a year or so in advance. Conversely, a shorter lead-time would preclude generation options that take longer to put in place.

6.28 Timing of reserve energy procurement is therefore a critical issue in the tender and contract design.

Legal Issues

6.29 The Commission will need to decide how any tender process is structured in legal terms. A key question is whether the tender process itself should create legal relations between the Commission and participating parties.

6.30 One option is to expressly exclude any legal or other obligations in relation to the tender process. Under this approach, the terms of any Request for Proposal (RFP) would provide guidance but have no legal force.

6.31 Alternatively, a tender could be structured as a "process contract" between the Commission and tenderers. As a contract, it would set out the rules and procedures to be followed in relation to tender form, content, timing, delivery, evaluation, consultation and selection.

6.32 If this contract question is not addressed expressly by the party requesting tenders, a "process contract" may still be inferred if it is clear that the parties intended to create legal relations with respect to the rules of the tender.

6.33 Two recent Court decisions are highly relevant to this issue: *Pratt Contractors Ltd v Transit New Zealand*[24] and *Onyx v Auckland City Council*[25].

6.34 A "process contract" is governed by the terms of the RFP, any accompanying documents and any relevant discussions between the parties. Following the Privy Council's *Pratt* decision, it is now clear that it will also be governed by various implied terms. In particular, an obligation on the party requesting tenders to:

- Treat all tenderers equally, and
- Act fairly and in good faith;

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24 [2003] UKPC 83 (Privy Council)

25 Unreported, High Court Auckland, CP 387/SD01, O'Regan J, 2 September 2003

- *Pratt* points out that these ”process contract” obligations do not mean that those evaluating the tenders have to act in a judicial manner. Further, the evaluation team may consist of people “with enough experience to have already formed opinions about the merits and demerits” of competing tenders;
- However, it is clear that any rules of evaluation included in a ”process contract” must be followed unless a right to vary or not follow them has been expressly provided.

6.35 If this ”process contract” approach is adopted, it will be important to reserve for the Commission appropriate discretions to:

- Vary its process;
- Accept or reject non-conforming tenders;
- Enter into negotiations or discussion with particular parties but not others, and
- Cancel the tender.

6.36 A ”process contract” may give potential tenderers more certainty and confidence in relation to the tender process. On the other hand, it also gives tenderers rights in relation to the Commission. A disappointed party may seek to recover damages for costs in preparing its proposal, for lost opportunity in failing to secure the final contract, and possibly for lost profits. Incentives may be raised to find a breach by the Commission of its “process contract”.

6.37 The alternative approach is to expressly exclude in the RFP any intention to create legal relations with respect to the tender process. The *Onyx* decision confirmed the legal validity of this approach. In a well-constructed non-binding tender, it should be possible to provide sufficient certainty and confidence to potential participants in relation to the Commission’s process without incurring the litigation risks that could arise under a “process contract”.

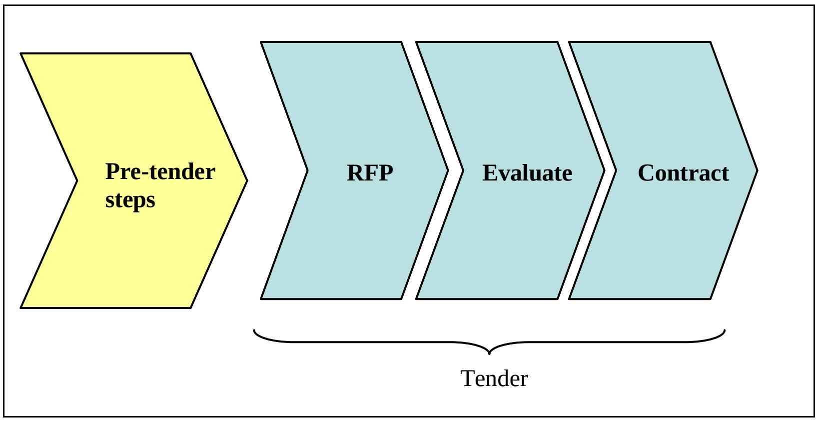
7. Tender Proposal

7.1 This section sets out a recommended structure and approach for purchasing reserve energy, taking into account the risks and issues discussed in the previous section.

Basic elements

7.2 Any tender process has four basic elements outlined in Figure 4: raising awareness and gathering information (pre-tender) steps, issuing a request for proposal (with accompanying contractual documentation), evaluating offers, then short-listing and contracting preferred offers.

Figure 4: Basic Tender Process



7.3 The core question is how to structure and refine these basic steps for a reserve energy regime so it delivers an optimal portfolio at least cost to the Commission and in a manner that minimises distortion to the ”ordinary” market.

Raising Awareness and Information Gathering

7.4 Given the embryonic nature of the reserve energy market, we propose that the Commission's first step is to develop a stronger awareness of potential opportunities among market participants. This could involve a series of activities including:

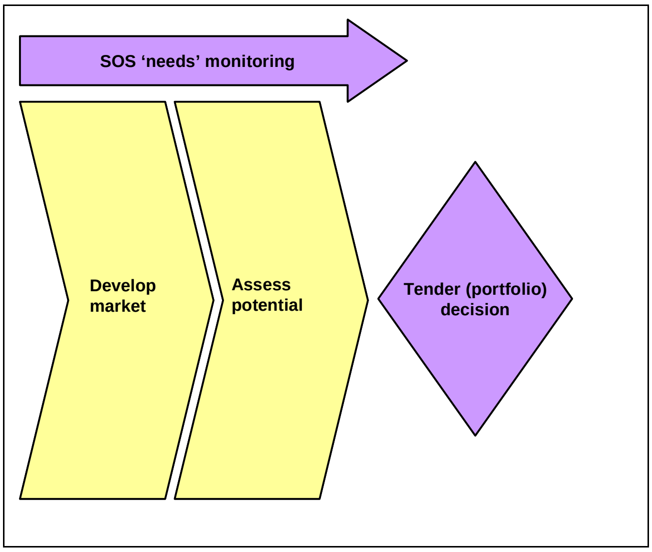
- Promotional material about the reserve energy regime, including flyers and newspaper notices;
- An invitation for market participants to register their interest with the Commission;

- Information for parties who register on key aspects of the process and possible sources of reserve energy; and
- A series of seminars to help interested parties identify and assess their opportunities to participate.

7.5 This leads to a preliminary assessment by the Commission of potential reserve energy sources, which is used in three ways: it feeds into the Commission's security of supply needs assessment; it informs the Commission's decisions relating to quantity, type and location of reserve energy to be purchased; and it helps refine the actual tender process.

7.6 Viewed diagrammatically, the proposed Raising Awareness and Information Gathering has four interconnected steps as outlined in Figure 5:

Figure 5: Raising Awareness and Information Gathering Process



7.7 Based on information gathering and analysis, the Commission decides on a mix of different reserve energy categories it considers most likely to best meet its security needs at least cost to the Commission. There are potentially three broad categories: generation, demand buy-back from larger customers, and reward schemes for smaller customers organised by retailers. Each category is likely to have different cost, benefit and implementation characteristics.

7.8 Based on its information gathering and analysis, the Commission also decides indicative quantities and locations for each reserve energy category. The Commission then proceeds to tender with an indicative reserve energy portfolio which it is seeking to fill at least cost.

7.9 The Raising Awareness and Information Gathering process has several advantages:

- It helps reveal the full range of potential reserve energy options;

- It encourages wider participation in the tender process;
- It provides a stronger information base for the Commission to make its decisions in relation to quantity, type, location and timing of reserve energy for the formal tender process;
- It enables the Commission to involve potential suppliers in developing standard contracts; and
- It enables the Commission to structure its formal tender process in a manner that focuses competition on key variables and reduces the problem of comparing offers with significantly different characteristics.

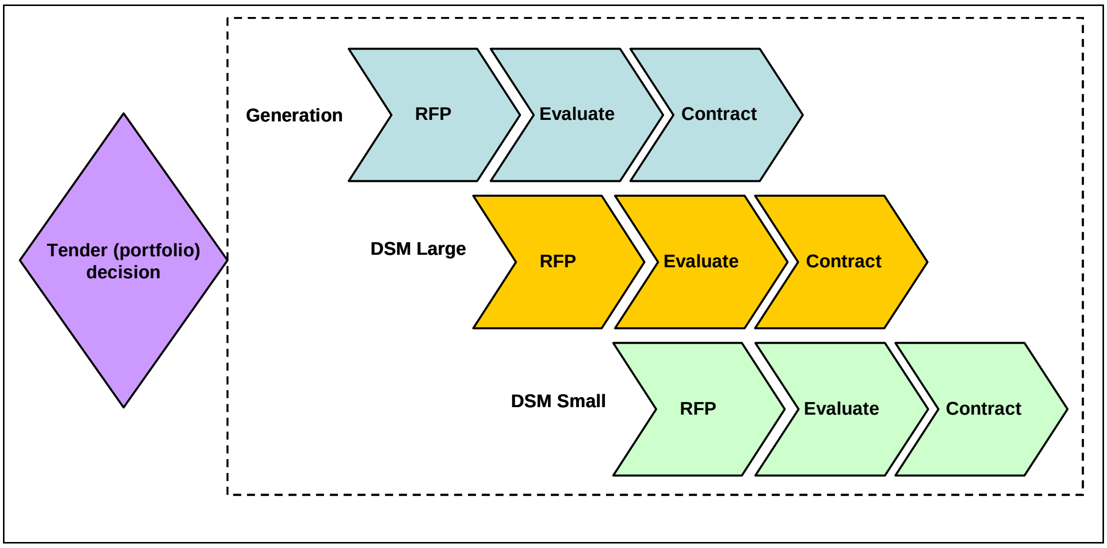
Formal tender

7.10 The formal tender process is structured to reflect the indicative portfolio developed in the Raising Awareness and Information Gathering phase. Rather than a single "all comers" request for tenders (RFP), the Commission issues distinct RFPs for each reserve energy category. Offers compete within their category-RFP. Competition on comparable key variables is therefore likely to be more focused and the evaluation process should be less complex than would be the case under a single "all comers" RFP.

7.11 Each category-RFP could be issued under a common "umbrella" set of terms and conditions. However, details relevant to each energy type would be set out in the relevant category-RFP.

7.12 An illustrative diagram of the recommended tender process is set out in Figure 6:

Figure 6: Tender Process



7.13 Under this recommended approach, the Commission may choose to tailor the timing of each category-tender. For example, it may run a tender process for some of its interruptible load needs closer to the relevant security risk period. In particular, large scale DSM tenders may be possible relatively close to the period of expected need. If the information gathering process reveals a lot of potential for demand-side reserve energy that could be organised relatively close to the period of expected need, the Commission could defer tendering until the need is clearly evident. If the Commission was concerned about a strategy of deferring tendering until very late in the process, it could contemplate running the demand-side tender earlier, and seek to establish options, the exercise of which would cause the supplier to organise the reserve energy just prior to the need.

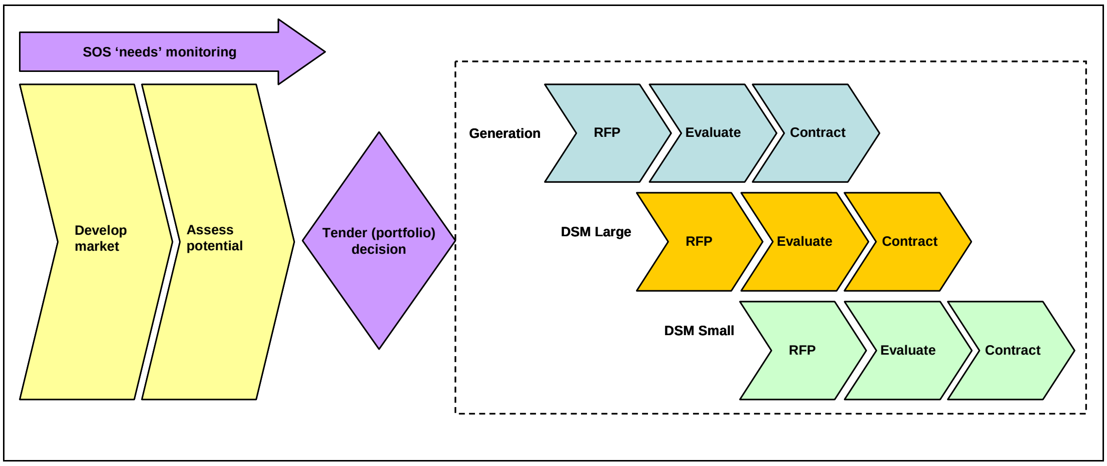
7.14 This category-based approach to tendering allows considerably more flexibility than a single "all comers" process, and is therefore more likely to avoid the risks of redundancy and distortion outlined in the previous section.

Summary

7.15 The proposed tender and contract regime seeks to blend the advantages of capturing a diverse range of potential reserve energy options with the competitive benefits of a more targeted tender. The information gathering stages are intended to reveal innovative low cost opportunities and inform the Commission about likely opportunities in different categories, while the tender stages aim to target competition within like categories and make cost/benefit comparisons less complex. An RFP for each key reserve energy category will also enable flexibility in timing tenders for all or part of the quantities required within each category. Another important feature of the proposal is the scope it provides the Commission to refine its security (Minzone) needs assessment in the light of changing market conditions.

7.16 The recommended tender and contract process is summarised in Figure 7.

Figure 7: Recommended Overall Tender Process



7.17 Alternative tender and contracting processes were considered, and these are outlined and evaluated in Appendix 2.

8. Reserve Generation

8.1 This section considers in more detail the types and features of reserve generation that could contribute to security and which might be considered eligible according to the parameters set out in the GPS.

8.2 The section first considers all forms of supply side generation that can contribute to security. It then attempts to address the eligibility of these different forms as required by the GPS. Finally it recommends the types of reserve generation that might be considered in a tender and the ring-fencing or other requirements that would need to be applied.

8.3 Potential reserves from demand reduction are considered in sections 10 & 11 of this report.

Need for additional security

8.4 It is assumed that a “needs assessment” looking out for 3 to 5 years has been completed and a quantity of reserve energy to be procured by tender has been determined[26]. This reserve energy is to provide security that is additional to that provided by the “ordinary” market within the time frame of the assessment.

8.5 It is assumed that a “need” for additional reserve energy has been identified for each year during the analysis period. It is recognised that beyond year 3 the identified need will be increasingly uncertain as it is highly dependent on the timing and nature of new “ordinary” generation investment. Beyond year 5 the “need” may not be assessed at all since this is beyond the lead time for ordinary new generation investment. It is likely that the assessed “need” will vary from year to year over the period as the balance of supply and demand changes with new investment.

8.6 It is also assumed that the “need” will be to provide additional security in a dry period. This will typically mean that reserve energy might be required to operate at high capacity factor for several months in dry years. The critical period is likely to be during May to October, or possibly April to November. It is not necessary for reserve generation to be instantly responsive in order to contribute to dry year security. Reserve generation that can be made available with reasonable notice (within a week or so) will be just about as valuable in a dry period as plant that can respond almost immediately. However, reserve generation needs to be able to operate at high capacity factor for sustained periods. Peaking plant that is energy limited will be less valuable in this regard.

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[26] This is covered in a separate report “Security of Supply Policy Development”.

8.7 While there continues to be transmission constraints within and between the islands, reserve generation in certain regions might be preferred. There may also be a preference for generation capability over certain times if hydro tributary and minimum releases restrict the quantity of thermal generation that can be used to conserve hydro storage during certain periods of the day or week (e.g. off-peak periods).

8.8 Conceptually reserve energy can be assessed in terms of the extent to which it lowers the hydro Minzone during the relevant years, or alternatively in terms of the extent to which it increases the 1 in 60 dry period energy margin during the critical winter period. The Minzone security assessment[27] incorporates all of the relevant factors including transmission constraints.

8.9 The GPS refers to reserve generation also being used to cover other risks, such as transmission or gas supply failures. Reserve generation can also provide additional security in these situations provided it is sufficiently responsive (i.e. can respond within hours or days), however the primary objective is to increase security during dry periods.

Supply options that can contribute to security

8.10 There is a raft of supply side options that could provide "additional" security to the market within the time frame of the needs assessment. These include:

- Building dedicated peaking plant such as the new plant at Whirinaki;
- Recommissioning old plant such as Marsden B;
- Renting dedicated peaking plant for a limited period (e.g. diesel plant on barges, use of ship generators in port, skid-mounted relocatable diesel generators etc);
- Building peaking plant within distribution networks to jointly manage distribution constraints and to provide reserve energy in a dry period;
- Building peaking plant within customer premises to jointly manage distribution outages and to provide reserve energy in a dry period;
- Expanding transmission to enable a greater utilisation from existing thermal and peaking generation during dry periods;
- Relocation of existing plant (reserve or ordinary) to achieve the same outcome;
- Increasing fuel supply or stockpiles for existing thermal plant beyond the level justified in the "ordinary market";

[27] As described in the separate report on "Security of Supply Policy Development"

- Deferring or compressing plant maintenance during dry periods so as to increase the dry year capability of existing thermal plant beyond that justified in the ordinary market;
- Advancing the construction of base-load plant beyond that justified by the ordinary market (e.g. taking additional risks by procuring plant in advance of obtaining resource consents or negotiating fuel supply, increasing construction costs through an accelerated construction program);
- Advancing the construction of a portion of a new plant (e.g. constructing the gas turbine component of a CCGT and running on diesel in advance of gas supplies being available);
- Reducing the level of instantaneous and load following reserve provided by thermal plant during dry periods so that higher capacity factors can be achieved beyond that expected in the ordinary market;
- Increasing the capability from existing generation (e.g. by investment to enable overload generation);
- Investing in dual firing of existing plant to increase dry year generation capability beyond that justified in the ordinary market;
- Deferring mothballing, retiring or decommissioning of existing plant beyond that justified by the ordinary market;
- Capacity or efficiency enhancements of existing hydro, geothermal or thermal plant beyond that justified in the ordinary market (e.g. additional wells at geothermal fields, re-runnering hydro plant, etc);
- Negotiation of additional resource consents that enable output from existing plant to be increased in dry periods (e.g. temporary increase in steam offtake in a dry year at existing geothermal fields with spare generation capacity).

Ring Fencing Requirements

8.11 Although there are many potential options to provide “additional security” the GPS is quite restrictive as to what would be considered eligible for a tender.

8.12 It states that:

- “Generation plant that is ring-fenced as reserve should primarily comprise plant with low fixed costs and high operating costs, including plant that would otherwise have been mothballed or retired, rather than base-load plant”, (*paragraph 52 GPS*);
- “The Commission should seek to minimise the impacts of the reserve generation on the ’ordinary’ market. The Commission should adopt a tight ring-fence whereby reserve energy may be used only for security of

supply objectives[28]. This will minimise the extent to which incentives to invest in ordinary generation and demand-side management are affected” (*paragraph 56 GPS*).

8.13 The requirement that reserve generation plant be ring-fenced is problematic for a large number of the options discussed above. In particular it would be difficult for the options that involve advancing new investment in ordinary plant ahead of that which would be economic as an ordinary market investment. It would also create difficulties for options involving modifications to the operation of existing generation, which would not be economic in the “normal” market.

8.14 Excluding all these options is likely to increase the cost of procured reserve significantly, since the only options that could be practically ring-fenced are dedicated peaking plant such as Whirinaki, recommissioned reserve plant such as Marsden B or dedicated rented or new oil fired peaking plant embedded within distribution networks or customer premises. However the ring-fencing requirement does make it much easier to determine if the new investments are “additional”.

8.15 The Commission is to review the ring-fence policy by the end of 2006, and we see significant merit in doing so[29]. However for this report we have assumed that the ring fence policy is in place and hence many of the available supply-side options to increase security in the medium term would be ineligible

8.16 The GPS allows a relaxation of the ring-fence policy for reserve generation may also be used for distribution network management. It would be consistent for reserve generation also to be allowed to provide backup to distribution outages, voltage control, spinning reserve or black start. In these situations the Commission will need to be convinced that the investments would not be justified on the basis of these alternative uses alone.

Contribution to Security

8.17 Note that, in principle, all generation plant (base-load, mid merit or peaking) contributes to security to the extent that it can provide a reliable energy contribution in a 1 in 60 dry period.

8.18 The total contribution to security will depend on a number of factors including the following:

- The certainty that the plant can be **commissioned by the required date.**

[28] With the exception of distributed generation used for distribution network load management

[29] The existing policy will increase the cost of procured reserve and may not significantly reduce (or possibly increase) the distortions in the ordinary market compared with an alternative more permissive policy which is focused on “additionality” as the primary criteria for eligibility.

8.19 The Commission will need to be given confidence that reserve generation offers are technically and financially viable and can be commissioned by the required date. This will involve some assessment that any necessary resource consents, connection agreements, fuel supply arrangements etc can be obtained in time. The Commission will need to monitor and enforce achievement of development milestones.

- The **capability and reliability of the generation** – the greater the reliable GWh generation that can be sustained over a period of 1 to 6 months the greater will be the contribution to security.

8.20 This means that there needs to be adequate fuel stocks and supply arrangements in place to enable high capacity running for several months given limited warning (e.g. a week or so).

8.21 The critical period can be from April through to November or December, but will typically be focussed in the period May to August. Capability during other months will not be as valuable as during these critical periods, however it may have some value in a low probability very sustained drought period.

8.22 The Commission will need contractual and other assurances (eg penalties) that fuel supply arrangements and plant reliability are adequate. It will also need to define preference weight factors for capability over different months where this varies over the year.

- The **location of the generation** – with the order of preference being, South Island, lower North Island and then Upper North Island.

8.23 Critical droughts primarily affect South Island hydro. To conserve South Island storage it is often necessary to transfer power from the North Island to the South, however transmission constraints through Bunnythorpe and across the HVDC can become binding from time to time. This limits the ability for reserve energy located in the North Island to conserve hydro generation in the South Island, and hence limits the value of that reserve to contribute to security, particularly at the margin.

8.24 The Commission will probably need to provide explicit weightings to apply to reserve generation in each region when it evaluates different options.

- The **responsiveness of generation** – There is not a significant difference between reserve generation that can respond in one hour or 1 week in a dry period situation. However given that the GPS has stated that reserve energy is to be available for other unexpected emergencies then there is a slight preference for reserve generation that can respond quickly.

8.25 The Commission should require that reserve generation can respond within a week of being notified, and will provide some additional credit for faster responsiveness to reflect the value in increasing security during transmission, fuel supply or plant outages.

8.26 More detailed consideration of these factors in the design of reserve generation contracts (including the setting of penalties etc) and in the selection methodology are discussed in later sections of this report.

Other Criteria

8.27 When the Commission considers supply-side options, it will need to assess the contribution to security and the expected net cost of each. In addition to minimising the net costs of reserve generation the Commission is required to minimise the impact of reserve energy on the ordinary market. There is also a requirement to account for the flexibility provided by short term contracts.

8.28 These criteria are discussed in this section.

Net Cost

8.29 The GPS stipulates that generation plant is not to be owned by the Commission.

8.30 The Commission will contract for the reserve energy, which will give the Commission certainty that there will be the reserve energy provided when required and will give the supplier certainty of revenue to support investment in reserve energy. In particular the arrangements should provide that:

- The supplier will provide the physical capability and will be responsible for its maintenance;
- The supplier will be paid Capacity Fees for making the plant available and, when the reserve is called upon, will be paid a Variable Fee for actual output;
- The Commission has primary dispatch rights over the plant and owns the spot revenue.

8.31 The cost to the Commission of dispatching the reserve generation will be the difference between the spot revenue earned and the variable fee paid to the supplier. Since the Commission is required to offer the plant for dispatch at the higher of 20c/kWh or the Variable Fee then there should be a net "trading profit" provided that the Variable Fee is at least 20c/kWh. In certain situations it is possible that the Commission will need to dispatch the reserve generation (for security reasons) while the spot price is less than the Variable Fee. In this situation there may be a net "trading loss".

8.32 The net cost of a reserve generation offer will therefore be the present value of the Capacity Fees plus the present value of the expected "trading profits". As a general rule, the expected trading profits will reduce as the Variable Fee increases. As the Variable Fee increases the risk of a "trading loss" will also increase.

8.33 The expected level of the trading profit or loss in any given year will be difficult to assess since it depends on the probability the reserve generation is dispatched and on the level of spot prices during these periods. The latter will be a function of the supply and demand balance as well as market behaviour. Any indexation of Capacity and Variable Fees will need to be factored into the analysis.

8.34 It is possible that suppliers of reserve generation may want additional pricing elements (such as start-up or enablement fees). If these are allowed then they will need to be factored into the evaluation.

8.35 These evaluation issues are discussed in section 12 of this report.

Short Term Contracts

8.36 There is a significant issue with respect to the term of the contract for reserve generation. Suppliers of reserve generation that requires significant investment are likely to seek a long contract term to enable them to get a return on the capital. However at any particular time the Commission will only have determined a definite need for a relatively short period, eg 1 or 2 years within the 3 to 5 years ahead needs assessment time frame. Even towards the end of that period the certainty of any need will be reducing as ordinary new investment might occur to remove it. On this basis the Commission would probably prefer to contract for just the years that a need has been identified. In fact longer term contracting increases the risks of distorting the ordinary market.

8.37 It may not, therefore, be appropriate to compare bids simply on the basis of cost per unit of reserve provided irrespective of contract term as this would tend to bias the selection towards very long term contracts. The GPS explicitly states that the Commission must account for the additional flexibility provided by short term contracts.

8.38 Thus there is a clear preference for short term contracts but some guidance is required in how to trade off contract term and cost. This is discussed further in section 12 of this report.

8.39 It may also be desirable to consider short term contracts with options to extend at the end of the initial term, or at the time of a future tender round. Alternatively it may be possible to consider contracts in which the Commission paid a fee to secure the option for reserve generation in the future (the option fee might be needed to cover the costs of consenting and design, but actual plant commissioning could be delayed until the Commission called for it).

Minimising the Impact on the ordinary market

8.40 As a general rule the impact of reserve generation on the ordinary market will be reduced if the variable fee is higher[30].

8.41 This would indicate that reserve generation with a higher variable fee should be preferred over one with the same overall net cost but a lower variable fee. This issue is also addressed further in a later section of this report.

Generator Reserve Recommendations

It is recommended that the Electricity Commission agree that:

- to be eligible to participate in a reserve energy tender a reserve generation supplier will need to provide energy capability for several weeks or months during the critical risk period (April – November);
- the contribution to security should be assessed on the basis of the impact on the Minzone – this will take into account reliability, location and sustainable generation capability in the critical periods;
- reserve generation must be "additional" to that justified by the normal market, and initially it must be able to be ring-fenced and used only for security of supply objectives, network constraint management, backup for distribution outages, or ancillary services;
- there will be a preference for shorter term contracts covering the period of identified need and for higher variable fee contracts;
- reserve generation would be dispatched by the Commission (or its agent) in response to security concerns with a one week notice period. Reserve generation that is available on a shorter timeframe may be dispatched by the Commission to cover other contingencies.

[30] Reserve generation with a higher variable cost will tend to be dispatched less and will have a reduced price capping effect on the market.

9. Contracting for Reserve Generation

Introduction

9.1 This section sets out some of the key issues that will be involved in contracting for reserve generation and develops a recommended position on each issue. A draft contract "terms sheet", suitable for development into a full contract, is developed from this assessment and included in **Error! Reference source not found.**

9.2 The focus of this section is on contracting with a narrow range of the supply-side options outlined in Table 3. This is because the ring fencing requirement effectively eliminates many of the options.

Reserve Generation Contract

9.3 The GPS makes it clear that the Commission is required to contract with suppliers of reserve generation rather than own reserve generation.

9.4 Thus in broad terms the reserve generation contracts will likely specify that:

- The supplier of reserve energy will own the generation plant;
- The supplier will arrange and pay for the generation plant's network connection and metering equipment (to the contractual standard);
- The supplier will be paid Availability Fees for making the plant available and, when the reserve is called upon, will be paid a Variable Fee for actual output;
- The Commission will take title to the electricity at the point at which it exits the power station (this is traditional with Power Purchase Agreements);
- The electricity will be offered by the Commission to the system operator for dispatch;
- Spot revenue received during operations will be credited to the levy account.

Contracts for New Power Station Development

9.5 Where a new power station is being developed in order to provide reserve generation (such as the case with Whirinaki), then a development agreement will be necessary in addition to the reserve generation contract. This development agreement needs to provide the Commission with confidence that the supplier has a practical project that will deliver the agreed reserve generation according to a credible commissioning program. The development agreement therefore needs to specify:

- **Milestones:** A series of milestones covering resource consents, other permits, placement of orders, fuel supply contracts, connection, construction and commissioning;
- **Reporting:** A requirement to report progress against milestones and provide supporting documentation;
- **Inspection:** Rights for the Commission to have its agent inspect construction works and assess overall progress against milestones;
- **Penalties:** A set of specific sanctions for failing to meet milestones, combined with a requirement to deliver additional measures to recover or compensate any delays;
- **Security:** Depending upon the credit worthiness of the counterparty, it may be appropriate for security to be posted by the supplier to cover potential penalties;
- **Step-in Rights:** Persistent failure to meet milestones leading to reasonable doubt that the supplier will provide reserve generation in a reasonable time frame should provide step-in rights for the Commission. Because of the requirement that the Commission not own reserve plant, these step-in rights would need to allow for transfer of ownership to the Crown or another party.

9.6 Each development agreement will need to be tailored to suit the requirements of the particular project.

Fuel Management

9.7 Most reserve generation options are likely to involve thermal fuel of some kind. For reserve generation to provide security of supply, fuel supply arrangements will therefore be just as important as plant availability.

9.8 Many potential suppliers are expected to be fuelled by diesel, which has a well developed and flexible supply infrastructure. Reciprocating engines of around 1.5MW capacity each could use approximately 60 tonnes of diesel per week. The total consumption of 100 of such engines, ~ 6,000 tonnes/week, can be compared with New Zealand wide diesel deliveries of around 40,000 tonnes/week.

9.9 For diesel, fuel management issues are likely to include diesel degradation during long-term storage and, once significant dispatch has occurred, obtaining rapid replenishment of stocks before the on-site tanks empty. The supplier of reserve energy is likely to be in a better position than the Commission to manage fuel supply, and it is recommended that contractual responsibility for fuel supply be allocated to the supplier of reserve energy.

9.10 The Commission should consider a requirement that the supplier maintain fuel on-site to enable a minimum period of continuous running at the contracted level of output. Individual situations will vary however, and the fuel supply arrangements will need to be a matter for discussion and negotiation.

9.11 The Commission should also be satisfied that the plant's fuel supply arrangements enable replenishment of the on-site storage to support continuous running for durations up to that specified in the contract. The supply arrangements proposed would be part of the tender information to be assessed, and would form part of the supplier's contractual obligation

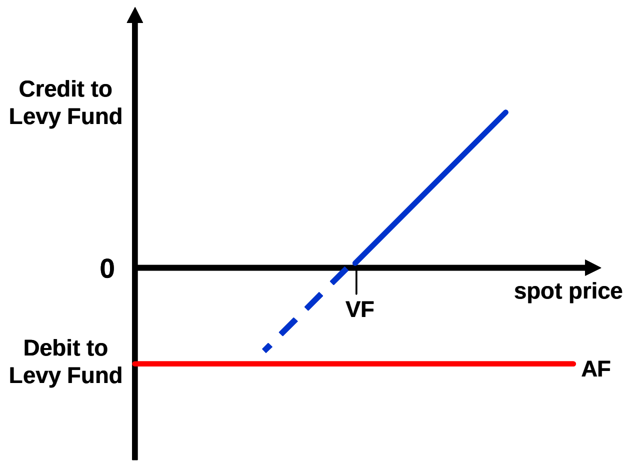
Payment Structure

9.12 The most appropriate payment structure for reserve generation includes:

- An Availability Fee (AF) payable by the Commission to the supplier that notionally covers the fixed costs of supplying and maintaining plant, and holding fuel in storage;
- A Variable Fee (VF) payable by the Commission to the supplier, for generation from the reserve plant when it is dispatched. This payment notionally covers the variable costs of production;
- Title to generation output transferring to the Commission when the output exits the plant. This means that revenues from the spot market will be earned at Spot Prices (SP) by the Commission and credited to the levy account.

9.13 The effects of these arrangements are illustrated in Figure 8.

Figure 8: Reserve Generation Payments



9.14 The annual cost of these arrangements is:

$$\text{Annual Cost} = AF - \Sigma_n [Q_n * (SP_n - VF)]$$

Where:

Q_n is the quantity of reserve energy dispatched in period n,

SP_n is the average spot price during period n, and

n is the number of periods in the year that reserve is dispatched.

9.15 During extended security constrained periods combined with high spot prices, reserve generation is likely to deliver large credits to the Reserve Levy Fund.

Plant Availability

9.16 It will be very important for reserve generation to be available, when dispatched, during a security constrained period. There are two aspects to availability that need to be considered:

- The plant needs to be available, with agreed notice, to run when called;
- The plant needs to perform reliably and produce reserve energy continuously over the period of a security constraint.

Addressing these issues in contract can be achieved through a mixture of incentives and penalties to encourage performance, and rights to inspect facilities and conduct test runs. Reserve plants are expected to run only occasionally, and may sit idle for many years. Achieving the right contract mix requires a trade-off between the cost of the service, the level of penalties for non-performance, and rights to inspect and test capability.

If the penalties are set too high, reflecting the very high cost to society if a plant fails to run when called, then providers could be discouraged from offering reserve. If penalties are set too low, the incentive to ensure availability may be insufficient. It is therefore recommended that the Commission seeks a balance between cost, the rights to test and inspect, and maintains penalties at levels that will encourage participation and performance, without discouraging providers.

9.17 To cover general plant availability it is recommended that the Commission consider a requirement for reserve generation contracts to include:

- A right to require test runs at regular intervals. This is relatively common for low capacity factor generation;
- A right to inspect (or use an agent to inspect) the plant, maintenance records and fuel supply arrangements;
- The payment of Availability Fees being dependent upon satisfactory test runs and inspections.

Such arrangements are likely to be the subject of negotiation between the Commission and reserve generation providers. However, the Commission needs to be satisfied that there is a high probability that reserve generation will be available, and will run reliably, when called.

Penalty for Shortfall

9.18 Because reserve energy is intended to be something of a "last line of defence", there should be an incentive on the supplier to take extraordinary measures to restore output very quickly should there be a breakdown during an operation period. A relatively high level of penalty for loss of availability is indicated even if it encourages tenders to include more profit margin and reduce the promised level of output.

9.19 For the purposes of responding to a dry year situation, it is appropriate to measure availability over weekly periods. For example, generation could contribute to dry year security even if it can only run for part of the day because of, say, night-time noise restrictions. The shortfall penalty would apply to the extent by which energy produced over the week, when fully dispatched, fell short of the contractually promised level of weekly output.

9.20 Under the circumstances in which the operation of reserve energy is intended, it is difficult to predict what spot prices will be and it is unclear how spot prices would relate to the value of lost reserve energy.

9.21 Penalty options that have been considered include:

Penalty	Comment
Spot price	A penalty equal to the spot price may be viewed as appropriate, however, under circumstances where the Commission is scheduling reserve energy with spot prices below VF, it may not provide an adequate incentive. Further, it may expose the supplier to an unmanageable exposure in the event of plant failure since spot prices are not capped in the New Zealand market.
Variable Fee	A penalty equal to VF could be argued to be appropriate because VF reflects the cost to the Commission of alternative reserve energy. However, when spot prices are higher than VF, the incentive to perform may be diluted.
Fixed Price	A fixed penalty set at a relatively high level of, say, 50¢/KWh would provide a strong incentive to perform, but may deter some offers and cause some parties offering higher Availability Fees than would otherwise be the case.

9.22 It is recommended that the standard penalty for under performance be set at the higher of 20c/kWh[31] and the lower of the Variable Fee and the Spot Price.

i.e. Penalty = maximum [20c/KWh, minimum (VF, SP)].

9.23 This should provide a balance between deterring potential offers and providing an appropriate incentive to perform the contract. In order to limit potential liability, an annual cap is proposed. It is recommended that this cap be set at a maximum of 500hrs of the variable fee at the contract capacity.

9.24 If sustained operation is required, there may still be a need for short interruptions to continuous running (to allow routine maintenance). Performance obligations should cover weekly output allowing for these factors, and the supplier should consider the need for short-term outages when establishing the weekly contract level.

9.25 For plant providing dry year reserve, there will be times of the year when it will be less likely to be required. Contracts should provide for planned maintenance at these times without incurring penalties.

Bonus for Exceeding Contract

9.26 The existence of a penalty regime is likely to lead to some conservatism in setting weekly contract reserve commitments. This means that additional output is likely to be possible from reserve generation. Such additional reserve is likely to be of benefit during a security constrained period when reserve generation is being dispatched.

9.27 Payment options for additional reserves that have been considered include:

Bonus	Comment
Variable Fee	The Variable Fee may be an appropriate bonus rate especially if it reflects short-run operating costs. However, there may be little incentive to generate more in these circumstances.
Spot Price	Spot price is effectively the short-term market value of reserve, but may not always cover short run costs.

9.28 It is recommended that the standard bonus rate for exceeding contractual reserve energy requirements be set at the rate of the Variable Fee.

[31] In line with the minimum dispatch price specified in the GPS.

Ring-Fencing Generation

9.29 Tight ring-fencing, together with a firm "additionality test"[32], are to be adopted (at least for the initial period) with a view to ensuring that distortions to the ordinary market are minimised.

9.30 The reserve generation contracts will therefore need to provide that:

- The reserve generation plant may only be dispatched at the request of the Commission (except for distributed generation intended for use in distribution network load management);
- The reserve generation will only be dispatched by the Commission to ensure security in a 1 in 60 dry year, if spot prices rise above 20c/kWh, and to help cope with unexpected supply contingencies, such as serious grid, plant, or fuel supply disruptions;
- Reserve generation plant that is also intended for distribution network load management may be dispatched by the distribution business only for bona fide network load management purposes, subject to the Commission's prior dispatch rights.

9.31 These requirements will limit the generation alternatives that will be eligible to provide reserve for the initial period. For example, existing generation that could be modified to provide additional output during dry periods, is unlikely to qualify.

Notice and Measurement Periods

9.32 The primary reason for providing reserve generation is to cover security of supply during dry periods. The New Zealand electricity supply system is energy constrained[33] during dry periods rather than peak constrained. This means that the system typically runs short of energy supply (MWh) to meet overall energy needs rather than power supply (MW) to meet peak energy demands. The important attribute of reserve energy suppliers is therefore their ability to provide energy over a sustained dry period rather than be available to immediately meet the demand for electricity.

9.33 Overall net welfare is therefore likely to be maximised if providers of reserve generation are allowed a reasonable notice period to arrange supply, and measurement of performance is undertaken over a period that reflects energy supply needs rather than peak supply needs.

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32 Any reserve generation is to be clearly additional to what would have been provided by the ordinary market

33 This means that the system typically runs short of energy supply (MWh) to meet overall energy needs rather than power supply (MW) to meet peak energy demands.

9.34 It is recommended that the standard notice period be set at one week and that measurement of performance is assessed weekly. Offerers would be free to offer shorter response times and this would be taken into account in the ranking, however fast response would not be required.

Force Majeure

9.35 A commercial contract including onerous performance obligations would be expected to include a force majeure provision. However, it is important that any force majeure provisions do not have the effect of materially reducing the incentives to perform to the contract. The standard form contract should therefore include a limited force majeure provision that is within the commercial principle of alleviating the supplier's ultimate liability under genuinely unforeseeable events, while not materially altering the incentives to take all precautions.

Dispatch Arrangements

9.36 The role of the reserve generation supplier will be to provide the plant, maintain the plant, meet all technical requirements, provide full supply, and operate the plant when dispatched[34] by the Commission.

9.37 The Commission's role will be to dispatch the plant during a security constrained period or when spot prices exceed the greater of 20c/kWh or the variable cost. Although the Commission may choose to contract the supplier as an agent for dispatch purposes, this will not necessarily be the case, and the Commission may also choose to use an independent agent.

9.38 In either case, the primary accountability for complying with, and meeting all costs relating to, the trading rules (Parts G and H of the EGRs) should remain with the Commission[35]. This creates a potential conflict for the Commission that is being addressed in another work stream.

Summary and Recommendations

9.39 Contracting for reserve generation can be reasonably straight forward, especially where a tight ring-fence applies and the plant is essentially only available for dispatch by the Commission. The key issues have been outlined in this section and a draft "terms sheet" is included as **Error! Reference source not found.**.

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[34] In this context dispatch does not mean the actual ordering of the plant to run – this will still be done by the System Operator. Dispatch in this sense, is the Commission setting the price and the operating rules to ensure that the reserve energy will be ordered to be run.

[35] Compliance with metering and connection and other non-trading aspects of the rules would be the responsibility of the reserve provider.

It is recommended that:

- Where a new power station is being developed in order to provide reserve generation then a development agreement be included in addition to the reserve generation contract;
- Fuel supply arrangements be included as part of reserve generation contracts for thermal generation;
- The most appropriate payment structure for reserve generation includes:
  - An Availability Fee (AF) that notionally covers the fixed costs of supplying and maintaining plant, and holding fuel in storage
  - A Variable Fee (VF) payable for generation from the reserve plant when it is dispatched that notionally covers the variable costs of production
  - Revenues from the spot market are paid to the Commission and credited to the Reserve Levy Fund.
- A penalty for under performance during an operation period be set at the higher of 20c/kWh and the lower of the Variable Fee and the Spot Price. In order to limit potential liability, an annual cap of 500 hours at the contracted capacity should also be established;
- A bonus rate for exceeding contractual reserve energy requirements be set at the rate of the Variable Fee;
- Due to ring-fencing requirements, reserve generation contracts provide that:
  - The reserve generation plant may only be dispatched at the request of the Electricity Commission (except for distributed generation intended for use in distribution network load management)
  - Reserve generation plant that is also intended for distribution network load management may be dispatched by the distribution business only for bona fide network load management purposes
- The standard notice period be set at one week and that measurement of performance is assessed weekly;
- The standard form contract should include a force majeure provision that is within the commercial principle of alleviating the supplier's ultimate liability under genuinely unforeseeable events, while not materially altering the incentives to take all precautions;
- The Commission should take primary accountability for compliance with Part G of the EGRs, but may choose to delegate to an agent.

10. Demand-side Reserve Energy

Introduction

10.1 There is considerable scope for end users to provide reserve energy by voluntarily reducing low value demand when security is threatened. In many situations this form of reserve energy can be expected to be cheaper than reserve generation alternatives. Demand-side reserves should be more flexible as they generally do not need a substantial investment in capital, are likely to be available on short-term contracts, and are likely to cost less in availability fees. However there are also a number of issues that arise when considering demand-side reserve options. These include:

- The variety of types of demand-side offers is large making it difficult to evaluate different demand-side offers or to compare them with supply-side options;
- For most potential demand-side options, this is not the offerer's "core business" and they will not offer if the financial rewards do not adequately compensate for the risks of penalties for non-performance, and the complexities involved in being part of the process;
- At a conceptual level it is possible for demand-side offers ranging from very large through to very small. For reasons associated with administering the tenders and verifying the demand response, the Commission will want to set a minimum (MW and MWh) participation level, however it should not exclude third parties who may want to combine these smaller loads in an amalgamated offer. These smaller loads may be able to make a significant contribution at a low cost, therefore helping the Commission achieve its objective of meeting the security standard at minimum cost;
- The demand-side has responded previously (to a limited extent) at times of high prices, and before conservation campaigns have commenced. A key issue is how to determine if the proposed demand-side response is additional to what may have happened anyway as a normal market response to high spot prices;
- The GPS requires that reserve energy should be "ring fenced" and only used when called on by the Commission; this is to minimise the extent to which normal market investment incentives will be affected. The actual physical systems that control an end-user's demand have uses that are not material to electricity investment (for example process control or providing for maintenance) and it is not appropriate to restrict such uses;
- Verifying the benchmark demand and the level of demand response for demand-side reserve offers is likely to be complex and difficult.

10.2 Each of these issues is explored in more detail in the following sections.

Possible Types of Demand-side Offers

Large energy intensive customers

10.3 These are generally customers where electricity makes up a significant part of their cost structure. Energy intensive industries, such as wood processing and aluminium production, typically have a lower value of output per unit of energy input and can be compensated for lost production at a lower price per unit of energy saved than other loads. These customers will often have some exposure to spot prices as they are likely to have fixed quantity contracts or other arrangements which mean that, at the margin, they pay or receive the spot price.

10.4 Given that spot prices are likely to be high leading into and during a security event, these companies should be interested in offering demand reserves at a relatively low cost.

10.5 Large customers may be able to shut down some or all of their operations during security events. However the level that they will be prepared to offer may be difficult to assess in advance as it is likely to depend on commodity prices, production orders, and stock levels at the time the security event unfolds.

10.6 There is also a question over eligibility as these customers may choose to reduce demand during these periods as a normal market response to the high spot prices, as evidenced in 2001 and 2003.

Medium size Industrial and Commercial customers

10.7 There are many large and medium sized customers that collectively offer the prospect of substantial demand reductions. Many national companies, for example, have operations spread throughout the country and may be prepared to select elements of their electricity consumption that could be reduced for periods of time without greatly impacting their overall operation (reduced lighting levels, unlit signage etc).

10.8 It may be feasible for individual customers to offer reserve directly to the Electricity Commission. Many sites will have half hour metering making measurement and verification easier. However, the nature of the tariffs (fixed price and variable volume) may remove the commercial incentive to participate and the relatively small size would create relatively high transaction costs for the Commission.

10.9 To avoid this a retailer could amalgamate customers, take advantage of diversity, and offer a collective demand reduction over a number of medium sized customer premises.

10.10 Amalgamating loads to provide demand reserves raises issues around additionality, ring fencing and verification as discussed in more detail later in this section.

Small commercial and domestic customers

10.11 There is potential for significant levels of demand response from relatively small users who have discretionary loads but are currently not incentivised to reduce demand during security events. This includes domestic and small commercial users who tend to be on standard fixed-price and variable-volume tariffs. The types of discretionary loads that could be involved include lighting, heating, air conditioning and electrical appliances.

10.12 A retailer could offer this type of customer a commercial incentive to reduce demand during a 1:60 security event. The retailer could then amalgamate the expected individual responses into a reserve energy offer.

10.13 Again there are difficult issues in demonstrating additionality (ie would the retailer offer this anyway based on their exposure to high spot prices) and verification (what is the baseline usage?).

Domestic market load control

10.14 Control of domestic load has been used for a considerable period of time in New Zealand as a means for distribution companies to manage maximum demand loadings, and hence delay investment in their networks. Generally this has been connected to hot water loads – during times of high network loading these loads have been switched off and switched back on some hours later when the network demand has reduced. Often the end user is not aware that the power has been off as the hot water stored in the cylinder has provided the energy buffer required.

10.15 A feature of the control of hot water use is that traditionally it has been used for load shifting with only marginal reductions in overall energy use. To achieve energy savings requires much longer periods with supply being switched off and a noticeable reduction of level of service for the end user. It may be feasible for either retailers or distributors to offer controlled loads as reserve energy. However, there may be complex issues around compensation for affected consumers.

10.16 There may also be cross-over issues if the loads are already offered as Instantaneous Reserves (IR) or committed as Automatic Under Frequency Load Shedding (AUFLS)[36]. The extent to which load control could be available as both reserve demand and as an *“emergency provision”* to cover worse than 1 in 60, is also an issue.

The Role of the Retailers

10.17 Most end-consumers take supply of electricity from retailers, who purchase energy, on behalf of their customers, from the wholesale market. The predominant supply arrangement takes the form of a fixed-price for variable-

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36 IR and AUFLS are services under the common quality regime in Part C of the EGRs.

volume as outlined in section 2. This is particularly the case for small consumers.

10.18 These arrangements meant that most consumers have no direct financial incentive to reduce demand during security constrained periods.

10.19 If consumers do make savings (for example in response to a call for savings to avoid future blackouts) the retailer tend to reap a financial benefit. This is because wholesale purchases at these times are likely to be at high spot price levels that exceed the fixed-price the consumer is paying to the retailer.

10.20 The retailer is therefore well-positioned to take a role in amalgamating small customer responses and provide composite reserve demand offers to be Commission. The savings the retailer makes on wholesale market purchases could be used to make the composite product more competitive as a reserve option than individual consumers would be able to achieve.

10.21 In practice, there may be barriers to the implementation of such schemes. These include:

- Mixed incentives on retailers because they typically participate in the wholesale market as generators;
- The cost and complexity of coordinating such schemes.

10.22 Nevertheless, the role that retailers may be able to play in the reserve energy market warrants further examination during the proposed raising awareness and information gathering phase.

Sources of reserve demand

10.23 Table 4 summarises the potential sources of reserve demand and summarises the characteristics of each.

Table 4: Characteristics of Reserve Demand

Supplier	Typical Characteristics
Large energy intensive customers	• Medium non supply costs • Exposure to spot prices • Relatively easy to contract with
Medium size customers	• Highest non-supply cost • On fixed tariffs • More complex contractually • Some transaction costs
Small customers	• Generally lowest non-supply costs, especially for initial tranches • On fixed tariffs • Most complex contractually • High transaction costs
Role of retailers	• Retailers are a natural intermediary for small customers • Relatively easy to contract with • Have mixed incentives that mean participation is uncertain

10.24 Large energy intensive customers are potentially likely candidates for reserve demand because:

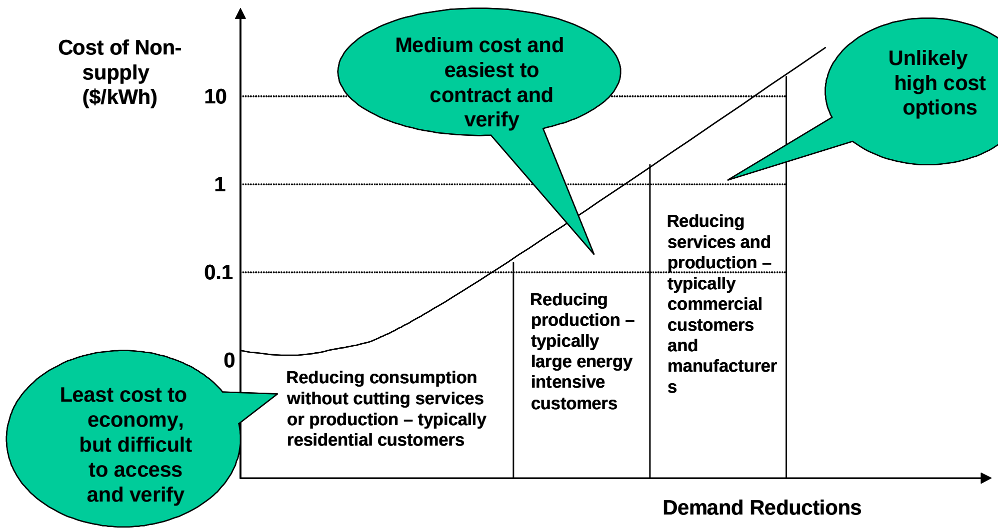
- They often have some exposure to spot prices;
- Costs of non-supply are potentially lower than for many less intensive customers;
- Contracting may be less complex.

10.25 Medium and small customers are less likely candidates because:

- They tend to be on fixed price tariffs;
- Costs of non-supply are potentially high for small industry and commerce;
- Contracting is likely to be complex.

10.26 Figure 9 is a stylised illustration of the potential supply curve of demand reductions that highlights some of these issues.

Figure 9: A Simplified Supply Curve of Demand Reductions



10.27 Figure 9 suggests that, although the large energy intensive users may be the easiest to contract with, and easiest to verify as additional, they may not represent the least cost to the economy. The least cost to the economy probably involves small users reducing consumption without cutting services on production. However, tendering for reserve energy from, and contracting with, small users is likely to face high transactional barriers, and retailers may not have sufficient incentives to coordinate small customer participation.

10.28 During previous electricity shortages some retailers of electricity have instituted small customer "reward-savings" schemes that were, at least, partially successful in securing low cost savings.[37] It could be possible to develop a similar arrangement, through retailers, that involved the Electricity Commission securing access to low cost savings as a form of reserve. An illustrative skeleton scheme is outlined in Appendix 6.

10.29 There are several difficulties with such an arrangement, including:

- The mixed incentives on retailers that may lead to weak participation;
- The need to estimate the likely effect of the reward-savings scheme on electricity demand – leading to uncertainty about the level of reserve energy available;
- Such measures not being considered as clearly additional to normal demand-side responses to higher prices;
- A perception that the Commission may be calling for national savings whenever it triggered the reward savings – this may be viewed as in

[37] Dunedin Electricity in 1992 and Mighty River Power (under the Mercury brand) in 2001 and 2003.

conflict with the GPS requirement to meet 1 in 60 security *"without assuming demand reductions from emergency conservation campaigns"* – however this issue could be clarified with the Government and managed in a way that avoided this perception;

- Potentially reducing the options available to the Commission to address dry periods that are worse than 1 in 60 by activating a national conservation campaign.

10.30 Although there are likely to be difficulties with the introduction of such a scheme, it does offer the prospect of accessing reserves that could provide a lower overall cost to the economy.

10.31 It is worth noting here that retailers are not the only party that could potentially amalgamate demand response in order to offer reserve energy. However, retailers may have a stronger commercial interest or proposition because of their exposure to wholesale spot prices.

10.32 There may also be a constructive connection between a DSM reward scheme for small consumers and the model domestic contract which the Commission is required to develop[38]. Such a model could provide the essential contractual elements required to operate a buy-back or reward savings scheme for small consumers.

10.33 The process of developing a model domestic contract could also explore the costs and benefits of encouraging, with the model, an option for some consumers to buy a fixed quantity (chosen by the consumer) at a fixed price, with more variable prices (reflecting, to some degree, changes in the spot price) for consumption above the fixed quantity. This approach would introduce a flavour of signalling scarcity of supply to a large segment of demand that currently receives no pricing signals at all if hydro inflows are very low.

10.34 The remainder of this section focuses on the issues associated with contracting for reserve demand with large customers.

Additionality test

10.35 A key concept raised in the GPS is that of additionality. It states that reserve energy should *"provide additional security of supply beyond the level achieved by the ordinary market."*

10.36 On the supply-side, the objective was that neither existing plant, nor new plant that would have been built anyway, would be eligible. Applying the same approach to demand-side options suggests that only additional response over and above the level of response that would have occurred anyway (for

[38] Paragraph 12 of the GPS

example because of price related response) would be eligible. To expand further, it is possible that companies who shut down operation in 2003 would not be eligible, existing demand exchange schemes would not be eligible, previously fired up back-up generation would not be eligible, nor would a lot of ripple control load. All of these have been used previously in response to high spot prices and could be considered as not clearly additional.

10.37 From a practical perspective deciding what was already in place and had been used previously in response to price would be difficult. The Security of Supply Policy Development project has suggested that price related demand response is difficult to forecast with any certainty and that, in ascertaining the capacity of the system, only a small allowance should be made for demand response. A practical position could therefore be for the Commission to allow demand response not included in the needs assessment to participate as reserve energy. If this approach was adopted, contracting for demand-side reserve energy would offer the prospect of firming up demand response that could not otherwise be assumed in the overall assessment of security.

10.38 Although this approach appears to provide a practical assessment of additionality, it may not be totally consistent with the intentions set out in the GPS. Therefore the Commission may need to be satisfied that contracted demand reductions are clearly additional to what would have normally occurred. This is a key issue for the Commission to resolve.

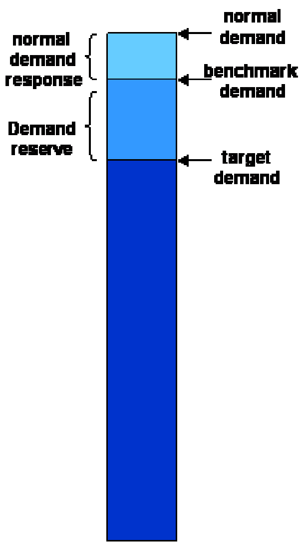
10.39 Contracting for reserve demand to assess additionality will involve a process of establishing and verifying the following:

- A level of **normal demand** (say for each week) that applies to the period over which reserve demand might be dispatched;
- A level of **benchmark demand** (for each week) that allows for any **normal demand** response that would be expected during periods of high spot prices;
- A level of **demand reserve** (for each week) that is the contracted demand response featured in the contract;
- A level of **target demand** (for each week) that is the **benchmark demand** less the **demand reserve.**

10.40 The **target demand** level is the weekly demand that the reserve demand supplier will be required to meet whenever the Commission calls for the dispatch of reserve demand.

10.41 These proposed definitions are illustrated in Figure 10.

Figure 10 – Defining Demand Reductions



Ring-fencing

10.42 Initially, at least, a tight ring-fence is to be adopted whereby reserve energy may only be used for security of supply objectives. This aims to reduce potential for changing investment incentives in the normal market and therefore helps to meet the Commission's objective of minimising the impact of reserve energy on the normal market.

10.43 Applying this strict ring-fence to the demand-side could infer that the systems to manage contracted reserve energy would not be available for any other purpose, or that any interruption to demand could only ever be through the dispatch of reserve energy. This is not practical for most loads and from an energy efficiency perspective would make little sense. For example it could imply running air-conditioning 24 hours per day, 365 days per year and only switching it off during a 1:60 event. Most demand-side offers on this basis would not be eligible.

10.44 Offers of reserve energy could come from demand reductions that interact with the electricity market in ways that are not price responses. An example is ripple control systems that manage demand so as to manage line loadings within a distribution network. Such operations could continue without changing investment incentives in the ordinary market.

10.45 In general, demand reductions that are eligible to offer reserve energy will not respond to prices until they reach levels likely to be well above the variable cost of reserve generation (say 20¢/kWh). Compared to generation alternatives, demand reductions are likely to be used less, and later.

Replacing reserve generation with reserve demand is not expected to increase the effect on investment incentives, or to require additional ring-fencing to ensure additionality.

10.46 Rather than attempt to impose a strict ring-fencing requirement on demand reserves, it seems sensible for the Commission to encourage demand-side participation and rely instead on an additionality test.

Conclusions

10.47 The key conclusions may be summarised as:

- Demand-side response is a desirable, flexible form of reserve energy, that can be provided with short lead times, on short-term contracts, and is likely to have the least impact on "ordinary market" operation;
- Large and medium size customers with exposure to spot prices are potentially good candidates for supplying reserve energy;
- Small customers on fixed-price and variable-volume tariffs have few incentives to participate;
- The Commission will need to establish a process for setting and verifying demand reductions and target demand levels;
- Retailers should be encouraged to provide savings schemes involving small customers;
- Demand-side reserve energy offers should comprise an agreed reduction in energy demand relative to an agreed benchmark demand;
- The strict ring-fencing requirement in the GPS is impractical to apply to demand-side reserve energy;
- In practice it will be difficult to determine if a particular demand-side offer is "additional", and the Commission will need to establish and publish a set of criteria in advance of any tender. This set of criteria will then need to be applied in screening any demand-side reserve energy offers before evaluation.
- There are several complexities associated with reserve demand that suggest a relatively high degree of uncertainty about the quantity and price of what could be offered.

11. Contracting for Reserve Demand

Introduction

11.1 Contracting with reserve demand is likely to be more complex than contracting for reserve generation. This complexity arises particularly because of the need to verify and benchmark demand levels and the differing tariff arrangements likely to be in place between the supplier of reserve demand and their retailer. This section addresses the structure of payments for demand reductions, and issues around availability and performance, and develops some further recommendations that are used as the basis for the draft terms sheet included in Appendix 5.

Payment Structure

Large customers with spot exposure

11.2 Contracts for demand reserves with large customers that have spot price exposure should take the following form:

- An Availability Fee (AF) payable by the Commission to the supplier, that notionally covers the fixed costs of supplying the reserves;
- A Variable Fee (VF) that notionally covers the supplier's costs of non-supply;
- For each unit of saving the supplier would be paid VF less the spot price (when spot is less than VF) or nothing (when spot price is greater than VF).

11.3 The effect of these arrangements is illustrated in Figure 11.

11.4 The annual cost of these arrangements is:

$$\text{Annual Cost} = AF + \Sigma_n [Q_n * (VF - SP_n)]$$

Where:

Q_n is the quantity of reserve demand dispatched in period n;

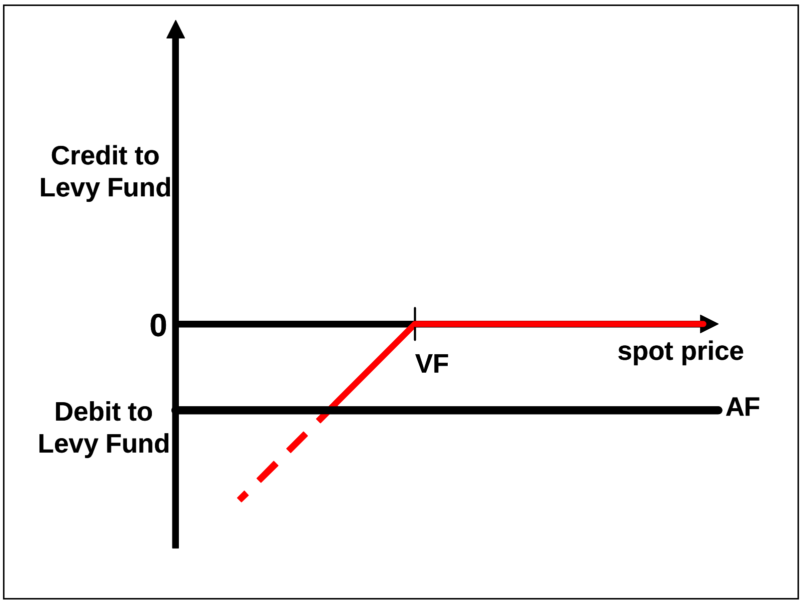
SP_n is the average spot price during dispatch period n[39]; and

n is the number of periods in the year that reserve is dispatched.

$(VF - SP_n)$ is only calculated when it is positive

[39] Typically weeks rather than half hours.

Figure 11: Reserve Demand Payments (Spot Customers)



Large Customers on a Fixed price Tariff

11.5 Contracts for demand reserves with large customers that are on fixed price tariffs, and therefore do not have spot price exposures, need to take a different form.

11.6 These contracts should include the Availability Fee (AF) and the variable Fee (VF), but the contract needs to provide for the payment of VF whenever reserve demand is dispatched, and regardless of spot price levels. The annual cost of these arrangements is therefore:

$$\text{Annual Cost} = AF + VF * \Sigma Q_n$$

11.7 In this case a spot price saving will accrue to the retailer providing the fixed-price tariff to the large customer.

Availability and Performance

11.8 It will be very important that contracted reserve providers reduce demand to the agreed target levels when dispatched. The Commission will wish to be confident that the reserve demand is available when called, and that performance is sustained over the dispatch period.

11.9 Inevitably there will tend to be unders and overs, and these will need to be accommodated within the contracts. A system of penalties and bonuses is recommended in order to incentivise availability and performance. As with reserve generation, the Commission will need to establish a balance between penalties to encourage performance, and encouraging participation. Again, it is suggested that the Commission holds penalties down to levels that will encourage participation, while asserting rights to test and inspect systems. The following arrangements are proposed:

- The Commission has the right to inspect and verify systems for achieving demand reductions;
- The payments of Availability Fees is dependent upon satisfactory verification;
- Performance relative to target demand levels is measured weekly, with credits and debits able to be carried forward over the period of dispatch noting that timing of savings may be important. For example there may be times when, due to constraints, savings may not be needed and reserve demand is "backed-off". Suppliers should not be penalised if this occurs;
- Penalties for under performance are set at the higher of 20c/kWh[40] and the lower of the Variable Fee or the average spot price during the dispatch period;
- i.e. Penalty = maximum [20c/KWh, minimum (VF, SPn)];
- Liability for penalties is capped at 500 hours of variable fees at the contracted demand reduction;
- Bonuses for over performance are set at 50% of the level applying to payments for contracted reductions[41].

11.10 The proposed penalty arrangement means that a supplier with fixed price tariff will still receive some net variable payment provided that they achieve at least 50% of the contracted demand reduction during a shortage period.

11.11 Suppliers with spot exposure will be able to earn higher availability fees, but will earn lower variable revenue during a shortage (as this is based on the difference between the variable fee and the spot price). In this case the potential penalties for failure are likely to exceed the variable payments if the shortfall is only 20% or less. This is appropriate given that they earn higher availability fees.

Force Majeure

11.12 As with generation, a commercial contract with onerous performance obligations would be expected to include a force majeure provision. Again it will be important that any force majeure provisions do not materially dilute the incentives to perform the contract.

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40 Reflecting the minimum dispatch price as prescribed in the GPS.

41 Note that this amount varies depending on the two forms of payment structure.

11.13 Relative to generation reserves, force majeure events that could impact on the ability to provide demand reserves are likely to be relatively limited.

11.14 The standard form of contract should include a force majeure provision that allows relief from the supplier's ultimate liability under genuinely unforeseeable events that impact on the ability to perform the contract. These should be relatively limited in scope.

Summary and Recommendations

11.15 Contracting for reserve demand is likely to be complex and involve tricky issues of verification and establishing additionality. A detailed term sheet is included in Appendix 5 that builds on the following conclusions:

The most appropriate payment structure for reserve demand supplied by large customers includes:

- An Availability Fee (AF) that notionally covers the fixed costs of the supplier;
- A Variable Fee (VF) payable for demand reductions (for customers with fixed tariff arrangements);
- A Variable Fee less spot price (when spot price is less than VF), payable for demand reductions (for customers with spot price exposure);
- Penalties for non-performance set at a level that does not deter possible demand-side offer or make them overly conservative;
- A penalty for under performance during an operation period set at the higher of 20c/kWh and the lower of the Variable Fee or the average spot price during the dispatch period. In order to limit potential liability, an annual cap of 500 hours of variable fees at the contracted demand reduction should also be established;
- A bonus rate for exceeding contractual reserve energy requirements set at 50% of the level applying to payments for contracted reductions;
- A standard notice period of one week and measurement of performance assessed weekly, with credits and debits able to be carried forward over the period of dispatch;
- A standard form contract that includes a force majeure provision that is within the commercial principle of alleviating the supplier's ultimate liability under genuinely unforeseeable events, while not materially altering the incentives to take all reasonable precautions.

12. Evaluation Issues

Tender objective

12.1 The aim of the tender is to procure reserve generation to cover any identified "shortfall" over the lead time of new base load generation.

12.2 The GPS requires the Commission to meet the security objective in a way that minimises both the long term cost of the reserve energy scheme and impacts on the "ordinary" market

12.3 As a general rule, minimising the impact on the "ordinary" market has been handled through the bid eligibility criteria (additionality test, and ring fencing requirements), limits on the total reserve energy to be procured, and the trigger mechanisms.

12.4 When contracting for reserve energy the Commission should adopt the objective of minimising the expected net preset value (NPV) cost of procuring and utilising reserve energy identified as necessary to meet identified shortfalls.

12.5 The GPS also states that reserve energy should be available to help cope with other unexpected contingencies, such as grid, plant or fuel supply disruptions. We interpret this as an incidental benefit that needs to be factored into the evaluation of offers but is not the primary consideration.

Evaluation in recommended tender process

12.6 In the tender process recommended in section 6 , there are two points of evaluation:

- First, at the end of the information gathering when, having assessed the market's potential for reserve energy, the Commission decides on an indicative portfolio of reserve energy "types" it will seek in the formal tender process; and
- Second, when offers have been received (in response to the request for proposal for the relevant category of reserve energy).

12.7 The first evaluation is carried out to help decide on the indicative portfolio to be tendered. The formal tender is split into a number of separate category tenders. In developing an indicative portfolio, the aim is to standardise some of the key variables and set target quantities for each category of reserve energy. The rationale for this approach is to focus competition in the formal tender and streamline the comparison of costs and benefits.

12.8 Both evaluations are likely to involve the same key steps, which are described below. However, there are also some important differences. The preliminary evaluation is likely to be based on assumed costs, availability and duration. These inputs can be managed by the Commission. By contrast, the formal tender evaluation will be based on actual offers, some of which may be individualised or non-conforming.

12.9 If the raising awareness and information gathering stage is effective, it should streamline the tender evaluation stage. The process of comparing offers within a category of reserve energy should be simpler if certain constraints are imposed in the RFP on the offers within a specified reserve energy category. For example, if offers all have the same term, type, location and variable fee then they can be ranked according to the availability fees per MWh reduction in the Minzone.

12.10 However, if the cost of the reserve offered for a particular category is significantly more or less than anticipated in the preliminary analysis, the target portfolio decided from the raising awareness and information gathering may have to be reviewed and adjusted. In this case, costs and benefits would have to be compared across energy types involving the steps outlined in the following sections.

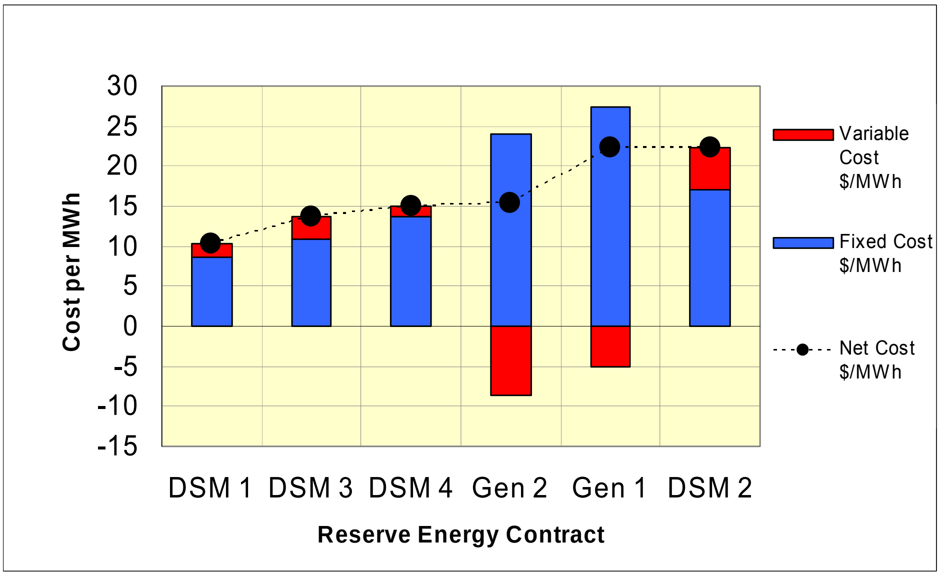
Key factors to be compared

12.11 The rest of this section summarises the main steps in the proposed evaluation methodology. Some of the steps involve mathematical and modelling techniques to scale data and project market outcomes. However, these are merely steps to calculate the main factor to be compared across all reserve energy options – **the net cost of gaining an additional unit of security**.

12.12 Each reserve energy option will have a total fixed cost, net variable cost, and an expected Minzone gain. In essence, the evaluation process is a quantification of these three elements for each year the option is contracted.

12.13 The outcome of the evaluation process will be a schedule for each option showing net costs relative to expected Minzone gains. Portfolio and selection decisions can then be made comparing the net cost per unit of Minzone gain as illustrated in Figure 12.

Figure 12: Ranking Reserve Energy Offers



12.14 In this illustration, the fixed costs have been converted to a cost per MWh, and combined with an expected variable cost to establish a net cost for each option. Note that, in the case of the generation options the net variable cost (for this example) is negative because of expected spot revenues earned by the Commission when the reserve generation is dispatched.

Steps involved in assessing offers of reserve energy

12.15 To assess each offer of reserve energy it is necessary to:

- Quantify the contribution it makes to dry year security;
- Quantify the net cost of the reserve energy being the sum of:
  - The fixed charges for having the reserve energy available for the Commission to dispatch; and
  - The variable cost of utilising the reserve net of any spot market revenues received.

12.16 Having assessed the contribution and cost in each year of the offered reserve contract, the expected net present value over the full term of the contract can be calculated.

12.17 A cost benefit ratio ($/MWh) equal to the present value cost ($k) divided by the present value of the contribution to security (GWh) can be derived and this can be used to rank offers.

Quantifying the contribution to dry year security

12.18 The aim of the tender is to lower the minimum zone to an acceptable threshold, hence the contribution to dry year security can be quantified on the basis of how much (GWh) each offer reduces the Minzone over the critical winter period (May to October).

12.19 The Commission will have the modelling capability to calculate the Minzone for monitoring purposes and this can be used to make this assessment for any form of reserve energy offer.

12.20 This method of measuring the contribution to security will account for differences in:

- the reliability of the reserve energy offered;
- the contribution from reserve in different locations due to transmission constraints;
- reserve energy capability and limitations by time-zone or month within the year;
- the priority of dispatch according to the variable cost[42].

12.21 The Commission will be looking to establish the <u>net</u> benefit of any form of reserve energy offer. This should include any detrimental impacts that could arise elsewhere in the market. For example a load normally offered as Instantaneous Reserve (IR) may be offered as Reserve Energy. If this was accepted there may be a detriment from the requirement for additional IR from elsewhere. In order to establish the contribution to security of some offers, the Commission may need to take into account operational issues and/or consult with the System Operator.

Assessing the net cost

12.22 The net cost is given by:

- Fixed Availability fees - as offered;
- Expected Variable Cost - Variable Fees net of spot market revenue.

12.23 Assessing the cost of the fixed availability fees will be straightforward. All that is required is that the monthly profile be determined accounting for any indexation and the present value total cost calculated.

[42] Each form of reserve with variable costs greater than 20c/kWh may be dispatched according to its "security based" guideline as recommended in the second preliminary report on Security of Supply Policy.

12.24 It will be more difficult to quantify the expected variable cost. In principle this involves a full simulation of the operation of the market to determine how often the reserve energy would be dispatched according to either the price, or security, trigger and what the spot price would be in these events.

12.25 While the Commission will have the modelling capability to assess the technical capability of the system given a starting hydro storage and fuel stockpile situation, this will not provide forecasts of the probability of reserve energy being triggered on the basis of price, nor will it provide an estimate of the likely level of spot prices in these events.

12.26 It is inherently difficult to make these assessments as they depend on the behaviour of market participants which will in turn depend on factors such as their contract position in dry year situations and their estimated value of water in storage.

12.27 Given this, it will not be possible to make objective accurate assessments. However some basis for evaluating offers is required since the net variable costs will vary as a function of the type of reserve (generation or demand reduction), the form of contract and the level of the variable fees.

12.28 Even though accuracy is not possible and judgements are required, it is still possible to develop a methodology that enables offers to be evaluated on a fair and consistent basis.

We recommend the following approach:

- A reference spot price duration curve is established with reference to historical prices and other benchmarks, with offsets for particular locations to reflect the probability of local transmission constraints;

- Dispatch duration curves for each type of reserve energy are derived as a function of their type and variable cost;

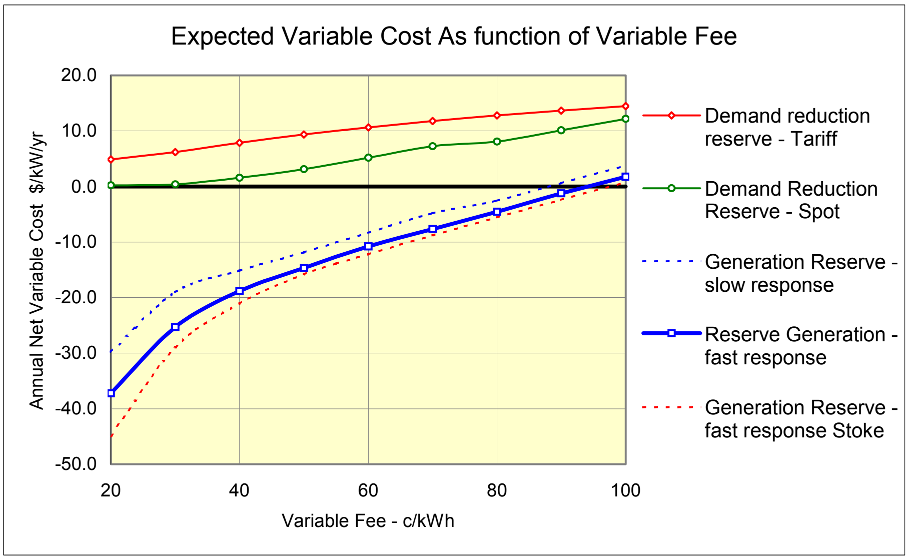
- A sliding scale for expected net costs for each type of reserve as a function of variable cost is derived from the spot price duration curve and the dispatch duration curve;

- This sliding scale is then used as a “look-up” table to determine the expected net variable cost for each offer as a function of its type and variable fee.

12.29 Note that the value of reserve energy helping to cope with “other unexpected contingencies” is reflected in the higher spot market earnings achievable by fast response reserve. This higher spot market revenue will reduce the net variable cost and is factored into the sliding scale for fast response reserves in the critical locations. Modelling may also need to include some sensitivity analysis of how changes to the spot price duration curve impact on net variable costs.

12.30 The details of this approach are explained in Appendix 3. Examples of the sliding scales for different forms of reserve are illustrated in Figure 13.

Figure 13: Illustrative Sliding Scales



Comparing offers of different term

12.31 The prime objective is to procure reserves for the identified shortfall in specific years within the time frame of the needs assessment (3-5 years ahead), however it is likely that tenderers will offer reserve for a number of years beyond that.

12.32 There is no certainty that any reserve is required beyond 5 years, hence it is not appropriate to value reserve generation offers beyond 5 years equally with those that contribute to the specific identified need in the first 5 years. In addition, the GPS explicitly states that the Commission must account for the additional flexibility provided by short-term contracts compared with long-term contracts.

12.33 On the other hand, valuing reserve energy offered beyond the identified need at zero would be unnecessarily harsh on the supply side offer, since there is a reasonable chance that the Commission will need to tender for additional reserve in the future, and long term reserve energy procured in an earlier tender can substitute for reserve procured in future tender rounds.

12.34 To provide an appropriate balance between long-term and short-term offers we recommend that the contribution from reserve energy offered beyond 3 years be discounted to reflect the increasing uncertainty that it is required. The rate at which the contribution is discounted could be 10% to 20% per annum. A 10% per annum rate would imply that the probability of there being a need had reduced to 60% after 5 years, whereas a 20% rate would imply the probability had reduced to 33% after 5 years. The choice reflects the Commission's judgement concerning the appropriate trade-off between short-term and long-term contracts.

Recommendations

It is recommended that the Commission agree that:

- The key criterion for evaluating reserve energy offers should be the net cost of examining an additional unit of security;
- The net cost of gaining an additional unit of security should be established by analysing the expected minzone gain and the expected net cost of each reserve energy option;
- The expected net cost should be established using a sliding scale approach as described in section 12 (Assessing the net cost) and detailed in Appendix 3;
- The contribution from reserve energy offered beyond 3 years should be discounted, to reflect increasing uncertainty, at a rate of between 10% and 20% per annum.

13. Implementation

Key steps

13.1 The key steps in implementing a tender for reserve energy according to the proposal outlined in this paper are:

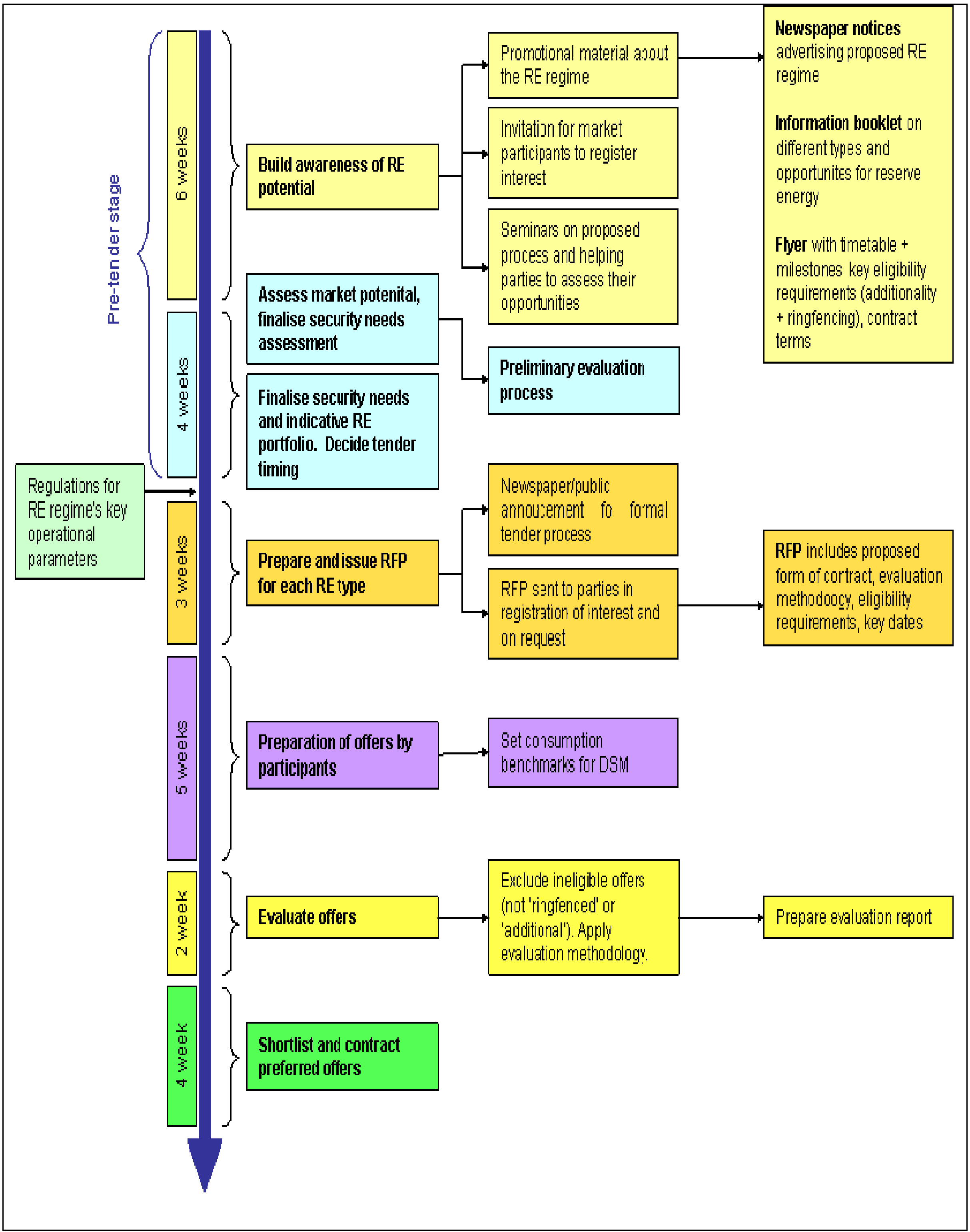
- Initiating the raising awareness and information gathering process to build awareness of reserve energy;
- Assessing the market potential following the information gathering;
- Finalising security needs and assessing tender options;
- Initiating a formal tender for reserve energy (by type);
- Evaluating offers;
- Short listing and contract negotiations.

13.2 These steps and an indicative time line are set out in Figure 14.

13.3 Overall, the raising awareness and information gathering stages are expected to take about ten weeks. The formal tender stages could take about a further 14 weeks.

13.4 The total process could be run as a sequential package over 24 weeks. Alternatively, the tenders could be timed to occur some period after the raising awareness and information gathering, as suggested in section 6.37.

Figure 14: Implementing the Tender Process



Project management

13.5 Implementing the reserve energy regime will be a significant and complex project, which the Commission will need to manage carefully. Some of the critical success factors include;

- An effective communications plan and strong relationship management with interested parties;
- High quality commercial and legal advice, particularly in relation to preparing and managing the RFPs, negotiations, purchase contracts and "due legal process";
- Specialists for evaluating offers. Among other things, this will involve dealing with non-conforming proposals, excluding ineligible offers and comparing different fees structures, contract term preferences and locational issues; and
- Efficient process management, including data-bases and administrative procedures.

Appendices

Appendix 1. Review of International Experience

1. Introduction

1.1 This Appendix:

- Identifies a number of overseas electricity markets that have experience of procuring reserve energy;
- Examines the different requirements for reserve in these markets and how this has impacted on the procurement process used;
- Summarises how each as approached to key issues, and highlights the similarities with and differences from, the NZ proposed approach and;
- Extracts key conclusions that are useful for the NZ situation.

2. Markets Considered

2.1 Reserve energy schemes are used in a number of overseas electricity markets. However because of differences in the generation mix and direction of regulatory policy, reserve energy schemes have tended to develop in different directions and with different objectives. The result is that the term "reserve energy" can have different meanings in different markets.

2.2 In the NZ market, hydro inflow variability is a major security of supply issue. In most other markets, security of supply concerns centre on whether there is sufficient capacity to meet demand during peak demand periods. Without the issue of hydro variability, reserve energy needs tend to be more predictable: additional reserve energy is needed as demand increases; less is required as new generation is added to the system.

2.3 The slow moving and predictable nature of reserve energy needs in most overseas markets tends to allow those markets to delay committing to the reserve energy until close to when it is needed, and to contract for short time frames.

2.4 In most markets, a regulator sets the required level of reserve energy and the mechanism by which the need is to be met. Where tender processes are used, we have examined these models in more detail (in Appendix 1) to see if there are lessons that can be incorporated into our approach to tendering.

2.5 The following markets / tender processes have been considered in some detail:

- **NEMMCO Victoria / South Australia 2002** : a forced outage of a thermal generator resulted in a projected shortfall in reserve capacity in a high demand period. NEMMCO tendered for short term reserve energy and included both supply and demand side;
- **National Grid UK 2003** : Moth-balling of older generation and projected high demand in the coming winter resulted in a projected shortfall in reserve capacity. The System Operator in the UK treated reserve capacity as a type of ancillary service. (Similar to NZ's instantaneous reserves but with longer time frames covering hours rather than seconds.) The National Grid Company tendered for short-term reserve and included both supply and demand side;
- **Northern Ireland Regulator 2003** : Uncertainty over a proposed new market for electricity trading led to a lack of investment in new generation. The Commission for Energy Regulation tendered for new base-load generation to meet the approaching short-fall in reserve capacity;

- **Western Australia 2002** – The Government decided that there was a lack of peaking plant in Western Australia and tendered for reserve generation to cover peak demand;
- **Townsville Power Station, Queensland 2001** : Similar to the Northern Ireland situation, the Government decided that there was insufficient base-load generation and tendered for new base-load generation to meet an approaching short-fall.

2.6 From these five tender processes we have concluded that the first two have the most relevance to the NZ situation. This is because they focus on short term capacity solutions, and allow for both demand and supply reserve energy options. Although these two tender processes do offer lessons for New Zealand, neither deals with the problem of hydro variability.

3. Summary of Findings from Overseas Markets

3.1 The following table summarises the approach to key issues in the five cases we have studied, and highlights the similarities with, and differences from, the proposed NZ situation.

	NEMMCO – Victoria / Sth Australia 2002	National Grid, UK 2003	Northern Ireland Regulator 2003	Western Australia 2002	Townsville Power Station, Queensland 2001
Need Assessment	250 – 300 MW of peaking reserve required to increase capacity margin to required level. Reduced capacity margin caused by an unplanned generator outage.	Supplementary Reserve tender to make up for projected shortfall in capacity. Shortfall caused by increasing demand – concern likely to be short-term due to high demand over winter.	300 – 531 MW new base-load generation to increase capacity margin. Concerns that new base-load generation not being built due to uncertainties with planned introduction of spot market	240 MW peak generation	> 150 MW base-load gas fired generation
Period when the Reserve Energy was likely to be needed	Contracts awarded by 23 Jan 2003 to cover period 10th Feb – 7th Mar 2003	Contracts awarded by 14th Oct 2003 to cover period 17th Nov 2003 – 1st Apr 2004	No defined period of concern	No defined period of concern	Commissioning during 2005
Types of Reserve Energy targeted	Supply and Demand	Supply and Demand	Base-load supply	Peaking supply	Base-load supply
Minimum Tender Quantities	10 MW	3 MW	50 MW	240 MW	150 MW
Maximum Call time (lead time to generate / make savings)	None specified	2 hours	None specified	"Short starting time"	None Specified

	NEMMCO – Victoria / Sth Australia 2002	National Grid, UK 2003	Northern Ireland Regulator 2003	Western Australia 2002	Townsville Power Station, Queensland 2001
Evaluation Criteria	• Availability Fee (Fixed fee / period) • Enabling Fee • Variable Fee • Certainty of delivery	• Availability Fee • Variable Fee • Quantity • Response Time • Restrictions on use • Location • Financial position of tenderer	• Financial position of tenderer • Plant must be centrally dispatchable and thermal • Capacity rate ($/MW/year) • Quantity • Operation Date	• Cost • Response time • Reliability • Technical specifications of plant • Suitable environmental characteristics	• Benefits to Townsville • Cost to Government • Regional development linked to additional gas supplies to area • Technical specifications of plant • Financial position of tenderer
Number of Offers	3	22	5	9	18
Quantity Contracted	None as plant returned to service before contracts awarded	20 offers accepted. Up to 800 MW	2 offers accepted totalling 550 MW	3 short-listed and 1 selected to build 240 MW	1 preferred bidder to build 220MW CCGT
Similarities with New Zealand Reserve Energy (Proposed process)	• Identifies shortfall and contracts to meet need • Only contracted for period where need is defined • Open for demand as well as supply side options	• Identifies shortfall and contracts to meet need • Only contracted for period where need is defined • Open for demand as well as supply side options	• Identifies shortfall and contracts to meet need • Focus on minimizing costs, that extra capacity is assured, and put in place relatively early (2 years after tender completed)	• Identifies shortfall and contracts to meet need • Focus on minimizing costs, that extra capacity is assured, and put in place relatively early (2 years after tender completed)	• Identifies shortfall and contracts to meet need • Focus on minimizing costs, that extra capacity is assured, and put in place relatively early (4 years after tender completed)

	NEMMCO – Victoria / Sth Australia 2002	National Grid, UK 2003	Northern Ireland Regulator 2003	Western Australia 2002	Townsville Power Station, Queensland 2001
Differences from New Zealand Reserve Energy (Proposed process)	• No PreTender phase to establish preferred reserve energy mix • Single tender open to any type of reserve energy to respond • Very short time from tender to possible use (3 months)	• No PreTender phase to establish preferred reserve energy mix • Single tender open to any type of reserve energy to respond • Very short time from tender to possible use (1 month)	• No PreTender phase – knew what they wanted and tendered for it • Focus on supply side, baseload options • Similar to our "Basic Tender" option	• No PreTender phase – knew what they wanted and tendered for it • Focus on supply side, peaking options • Similar to our "Basic Tender" option	• No PreTender phase – knew what they wanted and tendered for it • Focus on supply side, baseload options – linked also to gas supply to the region • Similar to our "Basic Tender" option
Comments	• Deliberately short time-frames to minimize possible impact of reserve energy on the "normal market" • As such aimed at existing generation options and demand side • Feedback from NEMMCO was that low number of bids was due to tight timeframes	• Deliberately short time-frames to minimize possible impact of reserve energy on the "normal market" • As such aimed at existing generation options and demand side	• Charged application fee to discourage frivolous offers • Complex evaluation criteria	• Question about whether technical specifications could have been stated more clearly: late in the process a short-listed bid was discarded because of inadequate technical specifications • Process took more than a year from initial EOI release to selection of supplier	• The evaluation process allowed for innovative concepts to be assigned a value, recognising the benefit of the innovation to the Townsville region and the overall Queensland gas market

4. Application of Overseas Experience to NZ

4.1 Key points that can be taken from the overseas experience are:

- The favoured means of keeping reserve energy costs as low as possible and ensuring that interference with the normal market is minimised, is to keep the timeframe between tendering for reserve energy and the requirement for reserve energy as short as possible, and to define a short duration of need;
- Applying short timeframes between tendering for reserve energy and the requirement for the reserve energy, has not meant that offers of reserve energy have been limited. Both NEMMCO and the National Grid achieved useful quantities of reserve energy offered within short timeframes;
- Offerers have been encouraged to offer reserve products to a common template so they could be readily compared on a similar basis;
- There has been a strong emphasis on the ability of the offerer to deliver the reserve energy. This emphasis has been critical in the evaluation phase of tender processes;
- In some cases the evaluation criteria have been clear to the prospective tenderers, while in other cases this has not been the case. In either case it is important that the organisation running the process is clear on the criteria at the outset in order to ensure that the relevant data is collected through the tender process, and that the evaluation can be readily made;
- Where the reserve needs are well defined and the types of reserve energy available are well known, then a relatively simple tender process can be adopted.

4.2 We have taken all these points into account when considering the most appropriate framework for New Zealand.

Appendix 2. Alternative Procurement Processes

This section briefly outlines three alternative approaches to procuring reserve energy. It then compares these alternatives against the proposal set out in section 7 in order to demonstrate the preference for the recommended approach.

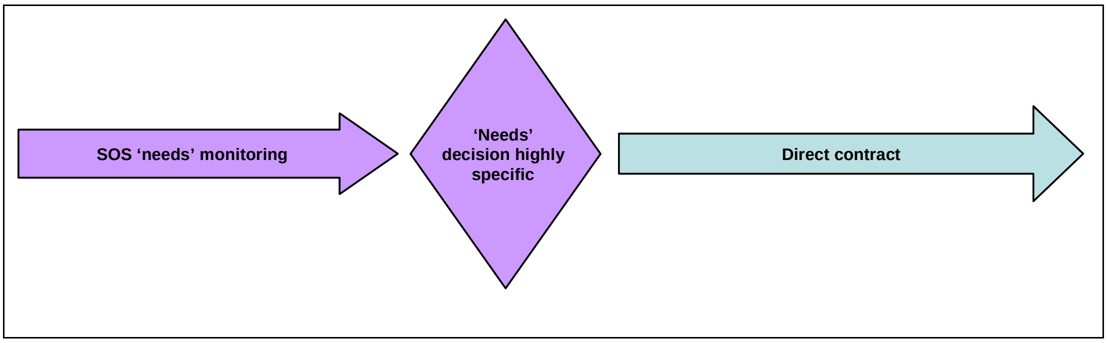
1. Direct contracting

1.1 The Commission could decide to contract directly with selected providers without a tender process. This approach may be considered if:

- The Commission's security needs assessment identifies reserve energy requirements that are highly specific in relation to location, timing and type;
- The Commission reasonably considers it is adequately informed of potential reserve energy alternatives;
- There is a high degree of confidence that the required reserve energy can only be provided by specific parties; and
- The detriments of a tender (time, cost and complexity) are reasonably likely to outweigh the benefits.

1.2 The key steps in direct contracting are set out in Figure 15:

Figure 15: Direct Contracting



1.3 Apart from failing to reveal innovative lower cost alternatives, a related key risk in direct contracting is lack of competition. This could have adverse impacts for the Commission in relation to price, allocation of risk and other key contractual terms. However, certain circumstances may arise when the pre-conditions outlined above can be satisfied and a case for direct contracting could be justified.

1.4 A decision to direct contract could also be made after the raising awareness and information gathering steps recommended in section 6.37 above. This would give the Commission more confidence that it was fully informed of potential reserve energy alternatives before deciding to by-pass a tendering process.

1.5 The decision to contract with Contact Energy to build Whirinaki was an example of Direct Contracting. In this case the Government decided that timing was the key determinant and Whirinaki was the only option that could be assured of delivering reserve energy for 2004.

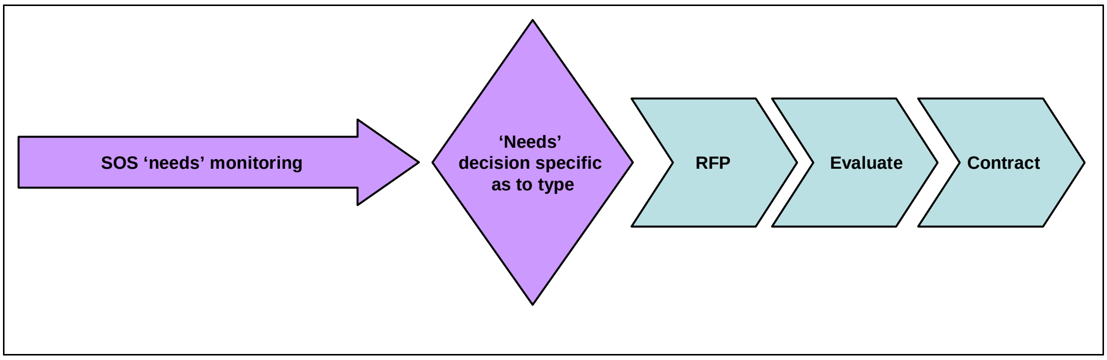
Basic tender

1.6 The Commission could run a basic tender for a fixed quantity of a particular type of reserve energy. This approach may be considered if:

- The Commission's security needs assessment identifies reserve energy requirements that are highly specific in relation to location, timing and type; and
- The benefits of a tender process are reasonably likely to outweigh the detriments of time, cost and complexity.

1.7 A diagram of the key steps in a basic tender for reserve energy is set out in Figure 16:

Figure 16: Basic Tender



1.8 The main advantage of this approach relative to direct contracting is the potential for stronger competitive pressures on price, risk allocation and other key contractual terms.

1.9 The main weakness of a basic tender is that it does not provide an opportunity to assess whether other types of reserve energy may more effectively meet the Commission's security needs. A basic tender is predicated on a single reserve energy solution without exploring possible alternatives. If a raising awareness and information gathering process as proposed in section 6.37 were to recommend a single category solution, then a basic tender process would be justified. However, without assessing the market's potential, it is unlikely that a tender process should exclude other reserve energy types.

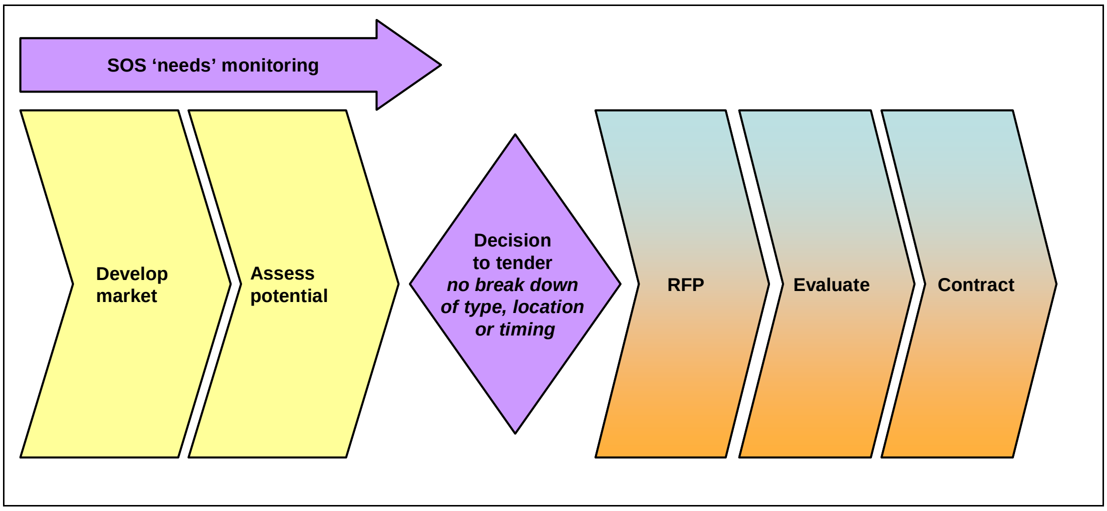
1.10 A number of the examples provided in the International Experience (Appendix 1) are forms of the Basic Tender.

2. "Discovery" Tender

2.1 This approach is similar to the proposal recommended in section 6.37, except that the tender is "global" – open to "all comers". It is not narrowed into a distinct category for each main energy type.

2.2 The "discovery" tender is illustrated in Figure 17:

Figure 17: A Discovery Tender



2.3 In this model, the decision to tender does not include a break down of types, location or timing. The aim is not to fill an indicative portfolio mix, but to discover through the tender a mix of options that best fills the required quantity. The tender documentation is therefore "global" covering all potential offers.

2.4 The main potential advantage of the "discovery" tender is that the optimal mix of reserve energy types is not decided until the tender evaluation stage. By contrast, this occurs after the preliminary market assessment in the proposal recommended in section 6.37. Not deciding the portfolio until formal offers have been received and evaluated may lead to a better choice of reserve energy options.

2.5 However, the key disadvantages of the "discovery" tender are as follows:

- Tender documentation is probably more complex and multilayered, with significant sections having no relevance to potential offers;
- It is less flexible in relation to timing. It does not readily allow for different categories of reserve energy to be tendered at different times; and

- The evaluation process is significantly more complex. Different variables and different assumptions from disparate offers have to be "levelled" and compared on a common base. In practice, it may be difficult to determine with confidence whether one offer is lower cost than another. The evaluation rules are therefore likely to be more open and flexible.

2.6 Together, these three detriments could discourage some parties from participating. This would lead to lower competition and choice for the Commission, which in turn could generate higher cost outcomes overall compared to the proposal recommended in section 6.37.

2.7 The NEMMCO and National Grid tenders detailed in Appendix 1 are examples of the use of the Discovery Tender. In both of these examples very short timeframes between tendering for the reserve energy and the reserve energy being required, precluded the use of an approach such as the recommended proposal.

3. Comparative summary

3.1 Table 5 summarises the key qualitative differences between the alternative procurement processes.

Table 5: An Assessment of the Alternative Procurement Processes

	Recommended Proposal	Direct Contracting	Basic tender	“Discovery” tender
Discovery of market potential	High	Low	Low	High
Quality of information for portfolio decision	Medium	Low	Low	High
Flexibility in tender timing	High	na	na	Medium
Simplicity of tender documentation	Low - medium	High	Medium	Low
Competition on key variables	High	Low	High	Medium
Evaluation complexity	Medium - high	Low	Low- medium	Very high

3.2 In most respects, the recommended approach to procuring reserve scores highly and, in aggregate, out-performs the other options.

Appendix 3. Tender Evaluation

1. Introduction

1.1 This technical appendix considers the evaluation of competing offers of reserve generation and develops a methodology for ranking offers on the basis of their contribution to security and expected net cost.

2. Tender objective

2.1 The aim of the tender is to procure reserve generation to cover any identified "shortfall" over the lead time of new base load generation.

2.2 The quantification of this shortfall is a separate exercise with its own issues as discussed in a separate report[43]. In this report the requirement is expressed as a need for additional reserve generation to bring the projected minimum zone below a critical level.

2.3 The Government policy statement requires the Commission to meet the security objective and:

- Minimise the long term cost of the reserve energy scheme;
- Minimise the impact on the "ordinary" market.

2.4 As a general rule, minimising the impact on the "ordinary" market has been handled through the bid eligibility criteria (additionality test, and ring fencing requirements), limits on the total reserve energy to be procured and the trigger mechanisms.

2.5 For the discussion below it is assumed that the objective is to minimise the expected net preset value (NPV) <u>cost of procuring and utilising reserve energy</u> identified as necessary to meet identified shortfalls.

43 "Security of Supply Policy Development: Discussion Paper", Concept Consulting Group, August 2004

3. Steps involved in assessing offers of reserve energy

3.1 To assess each offer of reserve energy it is necessary to:

- Quantify the contribution it makes to security;
- Quantify the net cost of the reserve generation being the sum of:
  - The fixed availability charges
  - The variable cost of utilizing the reserve net of any spot market revenues.

3.2 Having assessed the contribution and cost in each year of the offered reserve contract it is necessary to find the expected net present value over the full term of the contract and the net present value of the contribution to security. This enables a cost benefit ratio to be calculated which can be used to rank offers.

4. Generic Offers

4.1 Reserve energy offers may to take one of a number of generic forms. These were discussed earlier and are summarised below.

Reserve Generation

4.2 Under a generic reserve generation offer the Commission:

- pays a fixed availability fee (AF) each period (e.g. each month) to cover fixed capital and operating costs;
- pays variable fees (VF) for each MWh whenever dispatched to cover fuel and variable operating costs;
- controls dispatch and retains the spot market revenue from the generation.

4.3 The Commission will have the right to dispatch the agreed G MW at any time with a specified notice, or at any time within an agreed window (to allow for maintenance etc). There are penalties and bonuses for under or over performance.

4.4 It is possible that the availability and variable fees may be indexed (e.g. to PPI, exchange rate, fuel prices). In addition availability fees may possibly be front-loaded to match funding requirements.

4.5 The net cost to the commission is given by:

Net Cost = Fixed Cost + Expected Variable Cost

Where:

- Fixed Cost = AF the fixed availability charge;
- Variable Cost = $\Sigma_t\ G_t*(VF - SP_t)_{\text{when called;}}$
- SP_t = the market spot price in period t;
- G_t = the dispatched/metered generation in period t.

4.6 As a general rule it is expected that supply side bids will have variable fees around 20c/kWh. If this is the case, then the variable cost will typically be negative since spot prices are likely to exceed 20c/kWh when the reserve generation is dispatched. These credits (negative variable costs) will offset the fixed cost of this option.

4.7 It is possible that some tenderers may offer significantly higher variable fees. In this case there is a risk that the Commission may be required to dispatch the reserve when hydro levels fall into the minimum zone even though spot prices are less than the high variable fees. In these situations the variable cost can become positive.

4.8 It is also possible that tenderers may wish to bid additional variable fees such as start-up fees or enablement fees to cover start-up costs[44] or fuel stocking costs when the risk of a dry year becomes apparent.

4.9 These additional fees will add to the Commission's net cost and will need to be separately evaluated if they are significant. They may need to be factored into the effective variable cost of the bid to derive a trigger price for dispatch.

Demand reduction reserve

4.10 Under a generic demand-side bid the Commission:

- pays a fixed availability fee (AF) each period (e.g. monthly) to cover the systems and other costs of providing the capability to reduce demand when requested by the Commission;
- requires demand to be reduced R MWh below an agreed benchmark level for as many weeks as the Commission needs and pays variable fees for each MWh of promised saving delivered.

4.11 The agreed benchmark and reduction may be a MW profile or may be a MWh level for a day or week[45]. The degree of warning could be any time between a day and a week. Spot market savings that arise from dispatch of the demand reserves will accrue to the wholesale producer rather than the Commission. This makes the characteristics of demand reserves quite different to generation reserves[46].

4.12 Given the requirement for a warning period and the self-dispatch of demand reductions to meet a target over a week, it is unlikely that demand-side reserves would be generally offered into the market at a trigger price. It is

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44 Additional start-ups can significantly increase gas turbine maintenance and fuel costs (e.g. a start-up can cost 10 hours of continuous running). If the Commission controls dispatch then the supplier is exposed to the risk of significant additional costs that it has no control over and will find it difficult to estimate (since it is not clear exactly how the Commission will dispatch the plant).

45 It is necessary to specify a benchmark consumption as well as a reduction level since the reduction can not be measured and enforced directly.

46 Note that the GPS provides instructions for the trigger mechanism and "ownership" of spot revenues for supply side reserve energy. However is not entirely clear if these instructions should also apply for reserve energy from interruptible load. For this report we assume that different arrangements that are more suited to the supply of reserve energy from interruptible load can be used.

more likely that the Commission would trigger the load reductions by issuing a notice once the Minzone was reached[47].

4.13 The variable fees provide compensation for the customer reducing load. This compensation is equal to the customer's assessed own cost of non supply (CNS = lost profits from reduced production and increased costs including disruption and inconvenience costs etc) net of the saving in electricity purchase costs.

4.14 The structure of the variable compensation may take one of two forms depending on the customer's electricity purchasing arrangements (purchase at a variable volume/fixed price "tariff" or purchase of incremental load at "spot"). This gives rise to the two different forms of compensation described below[48].

4.15 Note that while these different styles of bid are based on assumed cost structures and electricity purchasing arrangements, customers are assumed to be free to choose whichever form they wish irrespective of their actual situation.

Variable Compensation for Tariff Customers

Net Variable Cost = $\Sigma_t [R_t*(CNS - tariff)]$ – whenever dispatched

4.16 This provides the customer with compensation relative to the cost of a fixed tariff. It is effectively a fixed cost to the Commission irrespective of spot price, since both the nominated CNS and the tariff will be fixed for a particular customer's bid. The total Variable Fee is thus CNS – Tariff. This is the most "intuitive" form of demand bid, and is probably the most likely form of bid to be offered.

Spot Based compensation

Net Variable Cost = $\Sigma_t [R_t*Max((CNS - SP_t,0)]$ – whenever dispatched

4.17 This provides the customer with compensation for demand reductions relative to spot prices in the event that the Commission dispatches the saving when the spot price is below the nominated CNS.

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47 Load reductions would reduce the level of demand to be met by hydro release from storage and hence help alleviate the shortage risk. Demand reductions would have an indirect impact on the market clearing prices, but would not set spot market prices directly.

48 Note that customers may possibly provide a range of different bids with increasing cost of non-supply to reflect the fact that small reductions may be achieved at a low cost but large reductions may be more costly and hence require greater compensation.

4.18 The Commission will face a cost, but only when the Commission dispatches the load reduction and the spot price is below the nominated CNS[49]. The cost is zero if the Commission waits until the SP = CNS before it dispatches the load reduction.

[49] Note that nominated CNS is also referred to as the variable fee (VF) for this style of reserve contract

5. Measuring the Contribution to Security

5.1 As discussed earlier, the aim of the tender is to lower the minimum zone to an acceptable threshold. The Commission will have the modelling capability to calculate the Minzone for monitoring purposes. The same modelling system can be used to derive the impact of any form of reserve energy on the level of the Minzone.

5.2 The critical period is winter and hence the contribution to security can be quantified as the GWh lowering of the Minzone over the period May to October.

5.3 This method of measure the contribution to security will account for:

- Differences in the reliability of the reserve energy offered;
- Differences in the contribution from reserve in different locations due to transmission constraints;
- Differences in generation capability and limitations by time zone/month;
- Differences in the dispatched according to variable cost (each form of reserve with variable costs greater than 20c/kWh may be dispatched according to its "security based" guideline as recommended in the second preliminary report on Security of Supply Policy).

Issues

5.4 This should be a relatively straight forward process for each year in which the security assessment has be carried out. The Minzone model can simply be run with and without the reserve generation and the average reduction over the relevant period calculated.

5.5 As a practical matter the following issues arise.

- The reduction in the Minzone may depend on mix of other reserves procured;
- The reduction may be different for different future scenarios (e.g. with different assumptions concerning the timing of planned or possible "ordinary" new plant;
- It is possible that the Minzone may not exceed the threshold each year in one or two of latter years in the needs assessment horizon. Procured reserve will reduce the Minzone in that year, but it is not clear that credit should be given for the reduction since the threshold has not been breached and hence there is no "need" for the Commission to procure reserve in that year.

5.6 With respect to the first issue we would recommend that each reserve offer be treated separately for the initial ranking. If there is a difference in the contribution as a function of the mix of other forms of reserve chosen, then this can be assessed at the final stages of evaluation.

5.7 With respect to the second issue, this can be dealt with by calculating a weighted average contribution over the different scenarios.

5.8 The third issue is more difficult. While there may be no “need” for the Commission to procure reserve in those years where the threshold is not breached, it is possible that the procured reserve may have value if the commissioning of “ordinary” generation new investments are delayed.

5.9 Another significant issue relates to the evaluation of the contribution to security in years beyond the needs assessment horizon (around 4 years from the tender or 3 years from the first year of “need”). In these years the need for reserve energy is highly uncertain as it depends on the timing of “ordinary” new investments beyond their lead time. It is quite likely that there is no need at all, for example in the years following a significant increment of base load capacity. In any event the “need” will become increasingly uncertain over time. To deal with this, we recommend that the expected contribution in years beyond the 3 years be discounted at 10% per annum. This is explained further in section 12.

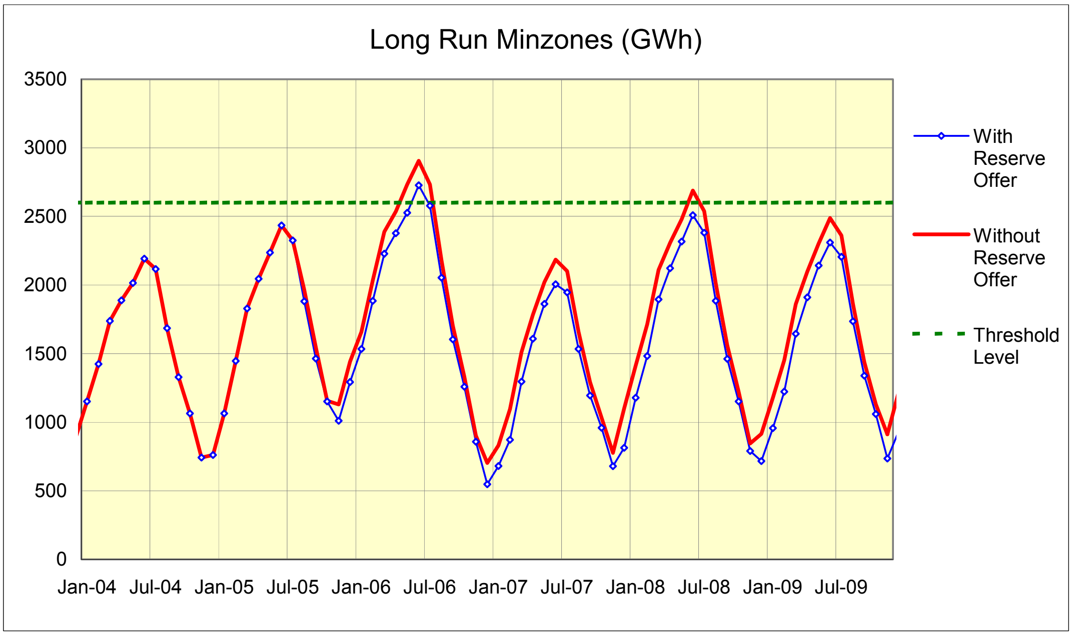
Example

5.10 The following is an illustrative example of the recommended process for assessing the contribution to security.

5.11 The first chart shows the Minzone calculated out several years. This is a hypothetical example assuming high demand growth and low levels of ordinary new investment until 2007, in which year a 300MW base load plant is commissioned.

5.12 As can be seen the projected Minzone exceeds the threshold in 2006, and again in 2008.

Figure 18: Illustrative Minzone Calculation

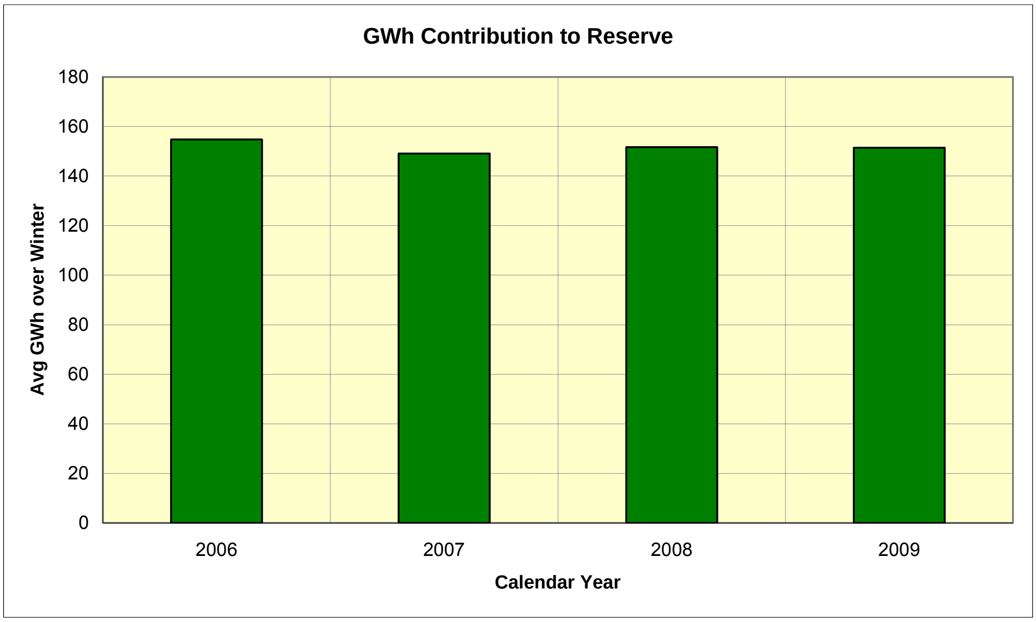


5.13 In this case there is an identified "need" in 2006 and in 2008.

5.14 The impact of an additional 40MW of reserve procured from April 2006 is shown by the blue line with markers.

5.15 The reduction in the average minzone each winter can be calculated and is shown in Figure 19 below.

Figure 19: Illustrative Calculation of Contribution



5.16 As can be seen the 40MW of reserve in the South Island lowers the winter Minzone by between 156GWh in 2006 to 150GWh in 2007. This corresponds to the energy from approximately 5 months running in the critical drought sequences[50].

5.17 The value of the reduction also needs to account for the probability that the threshold is breached in the identified year. For example in year 2007, the reserve generation will reduce the Minzone, but it is already below the threshold level since it is the year after a significant increment in capacity.

50 Note that these calculations are illustrative only. The actual assessed contribution using a more detailed Minzone model may vary from this assessment.

6. Assessing the Net Cost

6.1 The net cost is given by:

- Fixed Availability fees - as offered;
- Expected Variable Cost - Variable Fees net of spot market revenue.

6.2 Assessing the cost of the fixed availability fees will be straight forward. All that is required is that the monthly profile be determined accounting for any indexation[51] and the present value total cost calculated.

6.3 It will be more difficult to quantify the expected variable cost. In principle this involves a full simulation of the operation of the market to determine how often the reserve energy would be dispatched according to either the price, or security, trigger and what the spot price would be in these events.

6.4 While the Commission will have the modelling capability to assess the technical capability of the system given a starting hydro storage and fuel stockpile situation, however this will not provide forecasts of the probability of reserve energy being triggered on the basis of price, nor will it provide an estimate of the likely level of spot prices in these events.

6.5 It is inherently difficult to make these assessments as they depend on the bidding behaviour of market participants which will in turn depend on factors such as their contract position in dry year situations and their estimated value of water in storage.

6.6 It will not be possible to make objective accurate assessments, however some basis for evaluating offers is required since the net variable costs will vary as a function of the type of reserve (generation or demand reduction), the form of contract and the level of the variable fees.

6.7 Even though accuracy is not possible and judgements are required, it is still possible to develop a methodology that enables offers to be evaluated on a fair and consistent basis.

6.8 We recommend the following approach:

- A reference price duration curve be established on the basis of historical prices and other available benchmarks, with offsets for particular locations to reflect the probability of local transmission constraints;

[51] Note that there will be some issues associated with indexation. The Commission will need to make forecasts for inflation, exchange rates, the price of oil etc if these are necessary to calculate the indexation in the availability or variable fees.

- Dispatch duration curves for each type of reserve energy be derived as a function of their type and variable cost;
- A sliding scale for expected net costs for each type of reserve as a function of variable cost be derived from the spot price duration curve and the dispatch duration curve;
- This sliding scale is then used to calculate expected net costs for each offer which can then be combined with the fixed availability costs to derive a total net cost.

7. Establishing a Reference Price Duration Curve

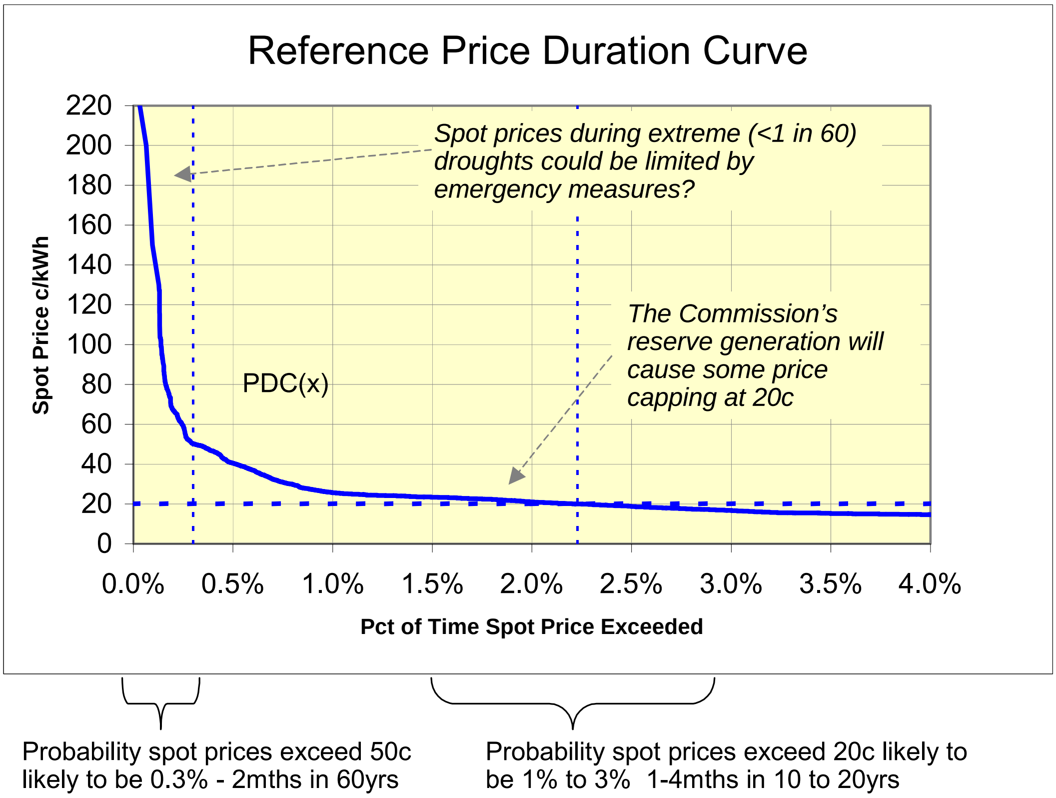
7.1 The spot price duration curve is the probability distribution that prices exceed a certain level.

7.2 Only the top end of the price duration curve is required to assess reserve energy, as this is the only time it is likely to be dispatched.

7.3 The chart below provides an example of the top end of the spot price duration curve that might be used to evaluate reserve energy offers.

7.4 The x axis value is the probability that spot prices exceeds the corresponding spot price on the y-axis. Figure 20 only shows the curve for spot prices above 15c/kWh, since Reserve Energy is very unlikely to be dispatched below this.

Figure 20: An Illustrative Reference Spot Price Duration Curve

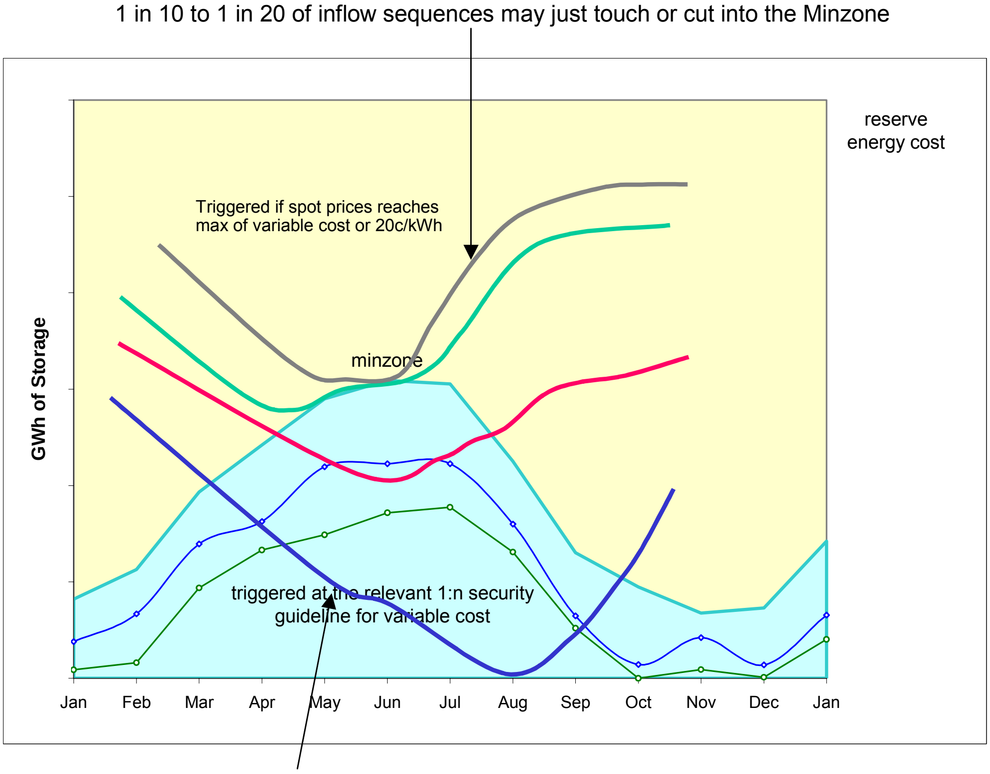


7.5 The following considerations are relevant in establishing this curve:

- The assumptions concerning the bidding behaviour and hydro storage valuation of “ordinary” generators;
- The probability that the Minzone is reached;
- The expected number of hydro trajectories within the Minzone, once it is reached;
- A degree of price capping that may arise from the Reserve Generation Policy;
- The extent to which spot prices might increase in the event that hydro storages reach very low levels within the Minzone;
- The potential impact of emergency measures on the spot prices at very low levels of hydro storage.

7.6 The Minzone represents the hydro storage level from which there is a 1 in 60 chance of requiring forced rationing. While the probability of requiring forced rationing is 1 in 60 the probability of reaching the Minzone is much greater. This needs to be assessed by simulation but could be of the order of 2 to 4 months, 1 in 20 or even 1 in 10 years. This corresponds to a probability in the range of 1% to 3%. As the Minzone is approached average weekly spot prices are likely to increase rapidly towards 20c/kWh and at peak times prices might exceed 20c/kWh. There will also be other situations where the spot price exceeds 20c/kWh above the Minzone. For example when there are short term capacity shortfalls or when transmission constraints are binding. Figure 21 demonstrates this below.

Figure 21: Illustrative Trajectories within the Minzone

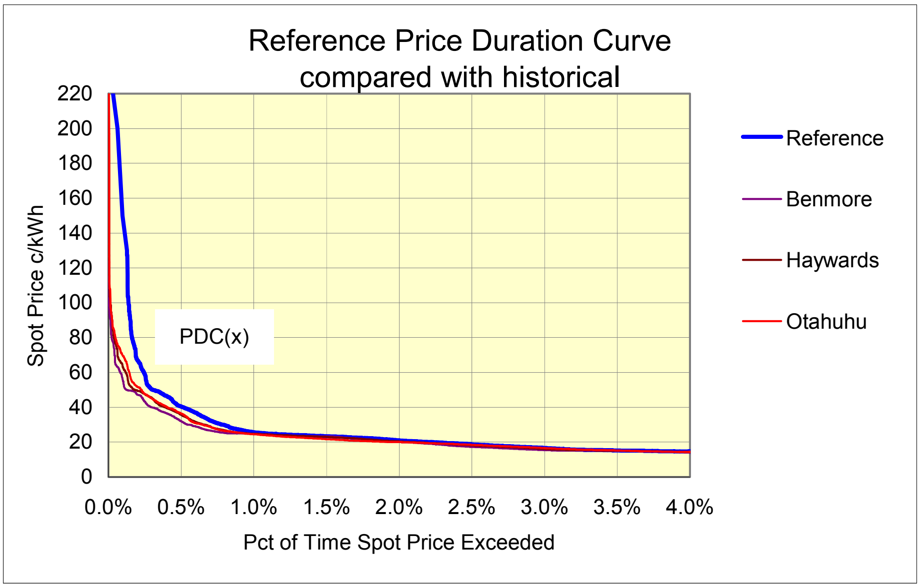


7.7 Once the Minzone is reached and all thermal plant and most reserve energy is dispatched it is likely spot prices will above 20c/kWh. In many cases the combination of running all thermal plant and all low variable cost reserve energy will arrest the fall in hydro storage and the Minzone will be exited rapidly. However there will be some situations in which the inflows are so low that despite the high level of thermal generation, hydro storage continues to fall. In these situations the risk of rationing increases and spot prices are likely to rise significantly above 20c/kWh, possibly as high as 100 to 200c/kWh. The number of these sequences is likely to be around 5-6 out of 72, and most will eventually have sufficient inflows to enable the Minzone to be exited within 4-5 months before rationing is required. The risk of prices exceeding 50c/kWh should be around 0 to 2 months in 70 years, or 0 to 0.3%.

7.8 It is also possible to compare the reference price duration curve with historical curves and to compare the area above certain prices with the generic cost of peaking plant.

7.9 Figure 22 below shows the price duration curve since the start of the market (October 1996 to April 2004). As can be seen, the general shape is consistent with the illustrative reference PDC. The key difference is the additional risk of up 0.3% in which spot prices could exceed 50c/kWh in worse than 1 in 60 dry years.

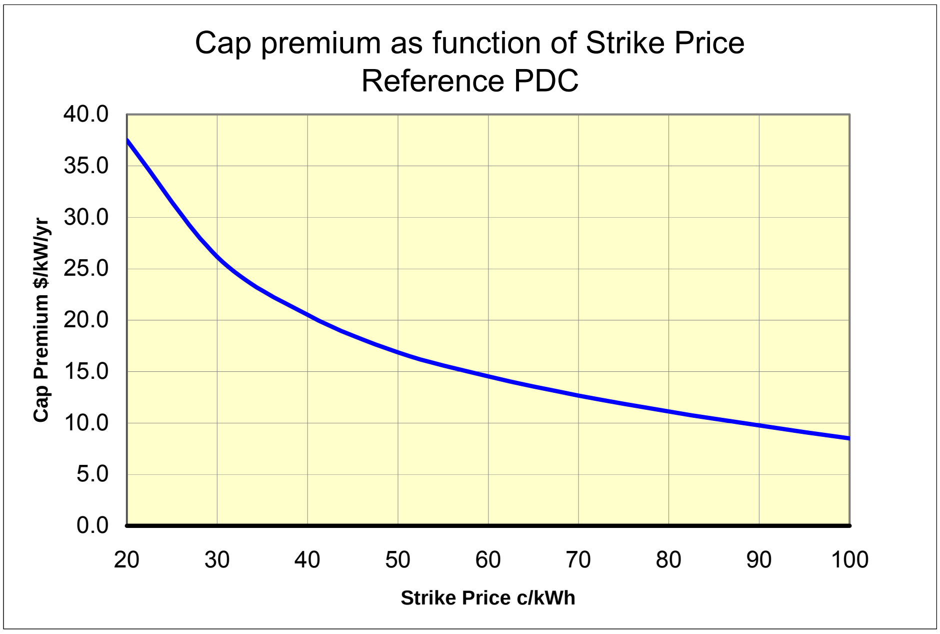
Figure 22: Reference and Historical Price Duration Curves



7.10 Another benchmark for assessing a price duration curve is the area above each price level. This is the value of an option contract with a specified strike price.

7.11 The option values for the reference and historical price duration curves are given in Figure 23 below.

Figure 23: Reference Price Duration Curve Cap Premium Function



7.12 The option values can be compared with the capital cost for new peaking plant. A typical diesel fired peaker with a capital cost of approximately $600/kW would require a 20c/kWh cap contract premium of around $70-80/kW/yr to breakeven.

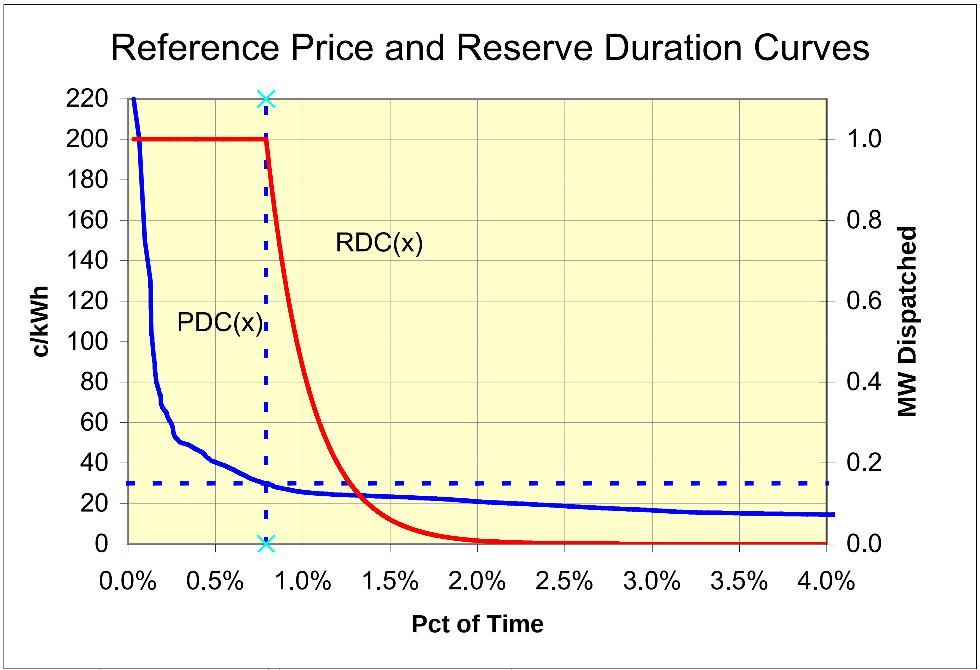
7.13 The Reference PDC has a 20c/kWh cap contract premium of $36/kW/yr which is approximately half the level necessary to justify new investment in a peaker. This to be expected otherwise there would be no reason to have a reserve generation policy.

8. Establishing the Dispatch Duration Curve for Each Type of Reserve Energy

8.1 As a general rule, reserve energy will be dispatched when spot prices exceed the variable cost. However it is possible for reserve energy to be dispatched according to a security guideline even though the spot price is not greater than the variable cost.

8.2 Figure 24 below illustrates the dispatch duration curve for a given form of reserve with a variable fee of 30c/kWh.

Figure 24: Reserve Dispatch Duration Curve for VF = 30c/kWh



Spot prices exceed 30c/kWh – there is a negative net cost

Reserve is dispatched for security when spot prices are less than 30c/kWh – there is a positive net cost

8.3 Figure 24 shows the price duration curve and the dispatch duration curve for generation reserve energy with a variable fee of 30c/kWh.

8.4 The generation reserve is fully dispatched to the maximum MW available when spot prices exceed 30c/kWh. During these periods the net cost will be negative (i.e. the spot market revenue will exceed the variable cost and a surplus will be generated that can be credited to the reserve generation levy fund).

8.5 There is also a chance that this reserve energy may be dispatched according to a security guideline when prices are below 30c. This possibility is factored in by the dispatch MW sloping down to zero rather than going to zero directly. During these periods the net variable cost will be positive and this will be a debit to the reserve energy levy fund.

8.6 The dispatch duration curve for other forms of reserve and other variable costs can be constructed in a similar fashion.

9. Deriving the Sliding Scale for Reserve Generation

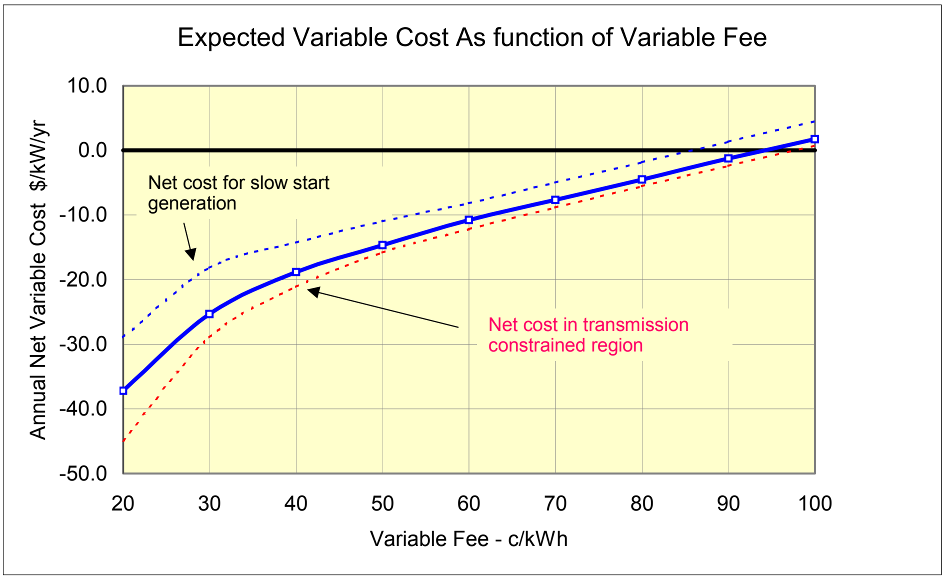
9.1 The expected net cost for any form of reserve with a given variable cost can be derived from the spot price duration curve and the dispatch duration curve as above.

9.2 The Expected net value is calculated

- $ENC(VF) = \int_x (VF - PDC(x)) * RDC(x)\,dx$

9.3 The calculations can be repeated for a set of different variable costs and a curve that represents the net cost as a function of variable cost can be constructed. The result of these calculation is illustrated by the solid blue line in Figure 25 below.

Figure 25: Net cost of reserve generation as function of variable cost



9.4 The expected net cost is negative for low variable cost offers. This will decline as the variable cost rises. At some level of variable cost the expected net cost will become positive. The net cost is expressed in terms of dollars per kW per annum so that reserve energy of different magnitudes can be assessed.

9.5 Where reserve generation is fast start and is located in a region which is susceptible to transmission constraints[52], then there will be an additional value

[52] Note that here we refer to regions in which local generation acts to relieve inwards transmission constraints. Reserve generation in those regions which face outwards transmission constraints would be penalised through a lower contribution to security.

which will offset the net cost even further. Figure 25 above (red dotted line) illustrates the extra value (negative cost) of fast start reserve in Stoke, for example. In practice, a separate sliding scale will be required for each transmission zone.

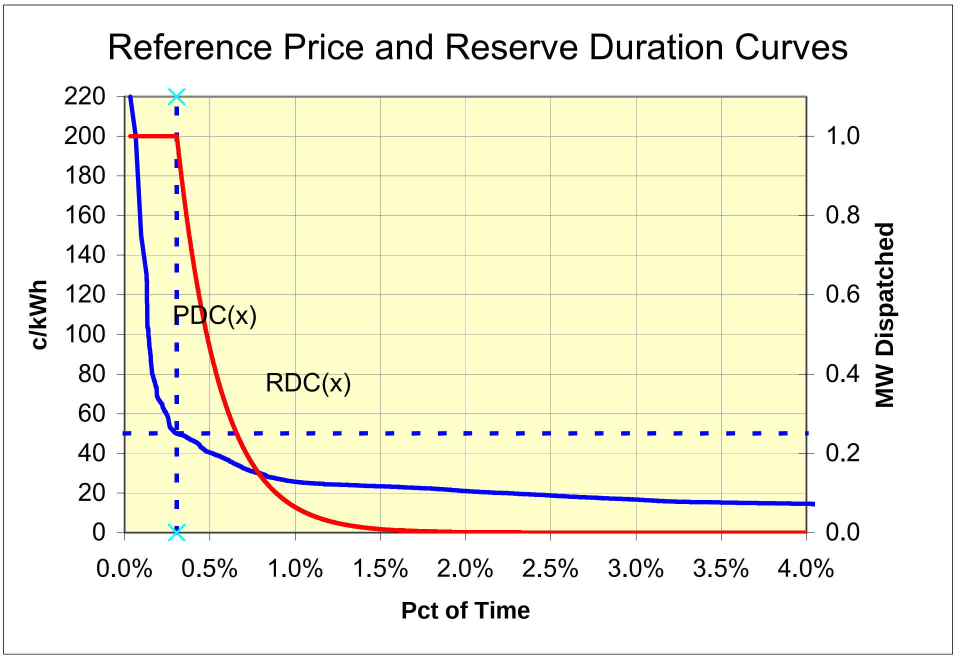
9.6 Where the reserve generation is slow start, (for example requires several days warning before dispatch) then the net cost will be greater since this plant will not obtain as much credit for short term response to the spot price trigger. The extent of the higher cost is illustrated by the blue dotted line in Figure 25 above[53].

[53] The dotted line is derived using a price duration curve based on average daily prices rather than half hour prices to illustrate the impact of less flexible and responsive price triggered dispatch.

10. Deriving the Sliding Scale For Demand Reduction Reserve

10.1 This sliding scale illustrated in Figure 26 is for generation reserve. Similar sliding scales can be derived for demand reduction reserve energy as illustrated below.

Figure 26: Demand reduction reserve with a VF = 50c/kWh



Spot prices exceed 50c/kWh – there is no variable cost

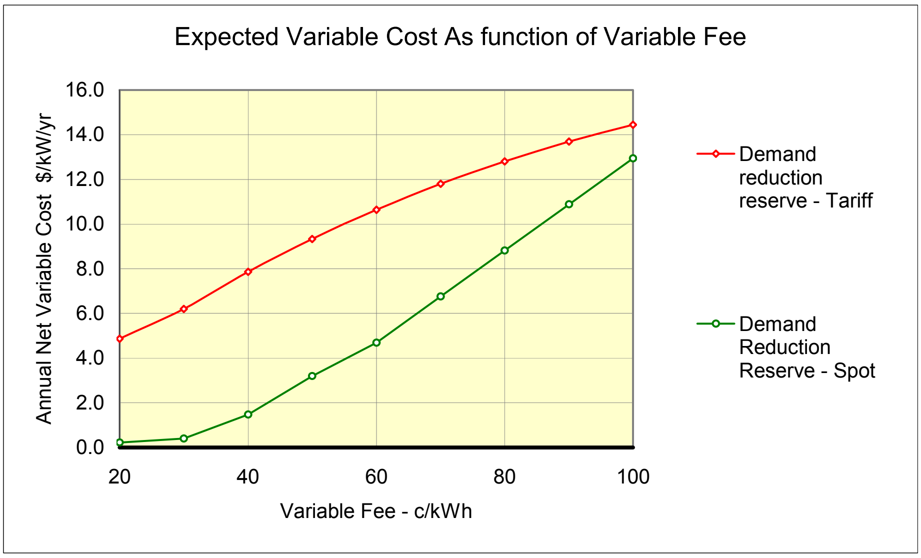
Demand reduction reserve is dispatched for security when spot prices are less than 50c/kWh – there is a positive net cost

10.2 The expected net cost for demand reduction reserve with <u>spot based compensation</u> is given below.

- $ENC(VF) = \int_x Max(VF - PDC(x),0) * RDC(x)\, dx$

10.3 As before the calculation can be repeated with different variable fees and a sliding scale for the net cost can be calculated. This is shown by the green line in the chart below.

Figure 27: Sliding scales for different forms of Demand reduction reserve



10.4 As can be seen, the expected net cost for demand reduction reserve with spot based compensation is relatively low when the Variable Fee (or nominated CNS) is relatively low. This is because there is a high probability that spot prices will already be high when the demand reductions are called for. As the VF increases the chance that the demand reduction will be dispatched according to a security guideline when the spot price is less than the VF increases, and hence the net cost increases.

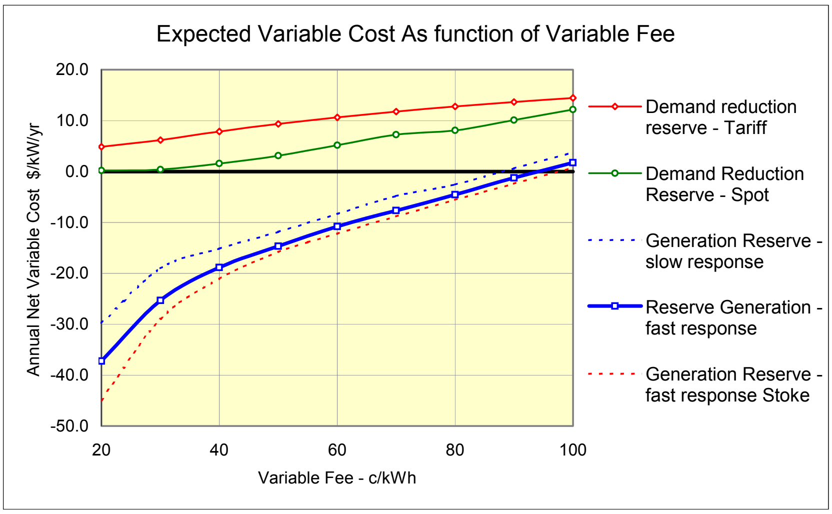
10.5 Figure 27 also includes the expected variable cost for demand reduction reserve with tariff based compensation[54]. This is shown by the red line in the chart above. It is always positive and is simply a function of the probability that it is called. This form of demand reduction reserve is likely to have the highest variable cost to the Commission and hence will be dispatched last. Figure 27 above assumes that this form of demand reduction reserve is dispatched approximately 1 to 2 months every 60 years.

[54] Note that the values on the x-axis are VF = CNS – Tariff for tariff based compensation, and VF = CNS-SP for spot based compensation.

11. Comparison Between Reserve Energy types

11.1 It is useful to put all the sliding scales for evaluating the net variable cost for different forms of reserve energy on one chart so they can be compared.

Figure 28: Comparison of Sliding Scales For evaluating variable cost for different forms of reserve energy as a function of Variable Fee



11.2 Figure 28 indicates, for example, that someone offering demand reduction reserve with tariff based compensation VF = 40c/kWh would need to offer a fixed availability fee approximately $27/kWh lower to compete with generation reserve with the same variable fee.

11.3 The difference arises because the Commission "owns" the output from the reserve generation and will receive a credit whenever the spot price exceeds the VF, however the tariff based compensation is always a net variable cost.

11.4 The credit for fast start reserve generation is also illustrated, as is the credit for reserve generation in transmission constrained regions.

12. Calculating the Net cost over Different Contract Terms

12.1 The prime objective is to procure reserves for the identified shortfall in specific years within the time frame of the needs assessment, however it is likely that tenderers will offer reserve for a number of years beyond that.

12.2 There is no certainty that any reserve is required beyond the lead time of new investment, hence it is not appropriate to value reserve generation offers beyond the identified need equally with those that contribute to the identified need. In addition the GPS explicitly states that the Commission must account for the additional flexibility provided by short term contracts compared with long term contracts.

12.3 On the other hand, valuing reserve energy offered beyond the identified need at zero would be unnecessarily harsh on the supply side offer, since there is a reasonable chance that the Commission would need to tender for additional reserve in the future, and long term reserve energy procured in an earlier tender can substitute for reserve procured in future tender rounds.

12.4 To provide an appropriate balance between long term and short term offers we recommend that reserve energy offered beyond the lead time of “ordinary” new generation investment be discounted to reflect the increasing uncertainty that it is required.

12.5 To implement this approach we recommend that a “levelised cost” is calculated for each offer which incorporates this discounting.

12.6 The levelised cost is calculated as follows:

12.7 For each year of the needs assessment out to the lead time of new generation ($y<3$[55] years) calculate:

- VC_y = expected variable cost ($k) from the sliding scale discussed above;
- CtS_y = contribution to security (GWh) from impact on Minzone.

12.8 Discount the contribution to security and the expected variable cost at 10% per annum[56] to reflect the increasing uncertainty for the need for reserve beyond this period.

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55 Note that the 3rd year of a reserve contract will typically correspond to the 4th year of the needs assessment horizon, since there will be a lag of at least a year between running the tender and the start of a reserve energy contract.

56 Note that the use of 10% per annum is illustrative. The Commission will need to choose a rate that reflects its assessment of the relative uncertainty concerning the need for additional reserve generation beyond the needs assessment horizon.

- $VC_y = VC_{y-1}*0.9$ .. for y>=3;
- $CtS_y = CtS_{y-1}*0.9$ .. for y>=3.

12.9 Calculate Effective Levelised Cost:

- Total NPV cost ($k) = $\Sigma_{y=1}^{N} (AF_y + VC)/(1+Dr)^{y;}$
- Total NPV contribution to security (GWh) = $\Sigma_{y=1}^{N} CtS_y/(1+Dr)^{y;}$
- Levelised Cost $/MWh = NPV Cost / NPV contribution to security.

12.10 Since the contribution to security is discounted by 10% p.a. from year 4 the effective levelised cost per unit will increase with contract term. This provides an explicit preference for shorter term contracts that reflect the increasing uncertainty concerning the need for reserve generation beyond the needs assessment horizon.

Example

12.11 The following charts illustrate the application of this methodology to reserve generation offers which are similar in all respects except contract term.

12.12 In this example the reserve generation offer has:

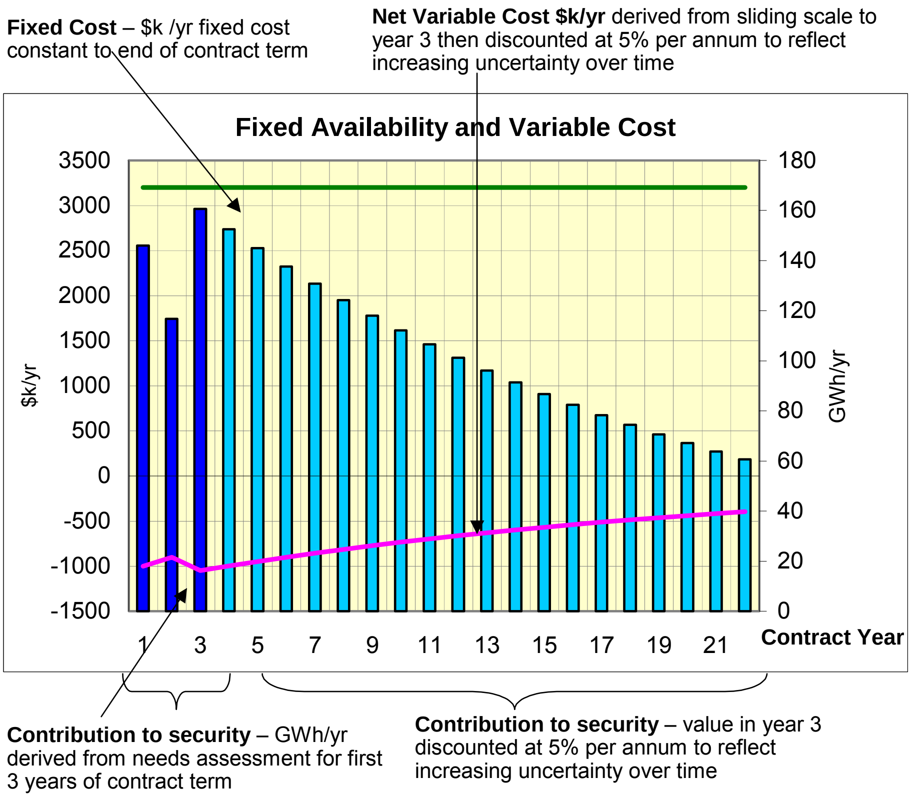
- 40MW capacity with a 95% availability;
- Fixed availability cost of $80/kW/yr;
- Variable fee = 30c/kWh.

12.13 As discussed in section 5 above the contribution to security can be evaluated from the reduction in the Minzone for each of the years in the needs assessment and then discounted at 10% per annum to reflect the increasing chance that the reserve energy may not be required after that time.

12.14 Net variable costs can be derived from the sliding scales discussed above and then discounted at 10% per annum beyond the needs assessment horizon.

12.15 The fixed costs are certain over the term of the contract and hence are not discounted.

Figure 29: Costs and Contribution to Security over term of contract

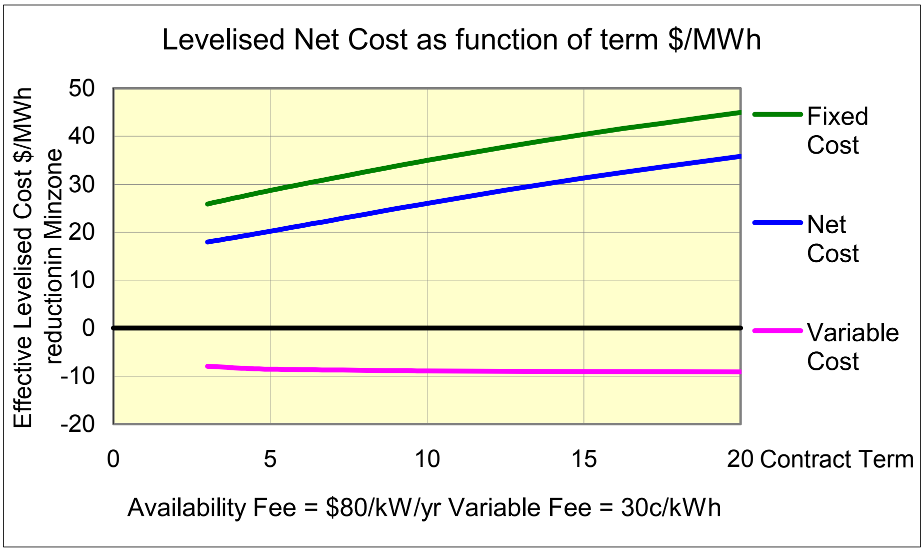


12.16 These costs and contributions to security can be present valued and the effective levelised cost calculated as per the formula given in Figure 29 above[57].

12.17 Figure 30 below shows the resulting effective levelised cost for contracts of different terms.

[57] A 7% per annum real discount rate is used in this example.

Figure 30: Effective Levelised cost as function of contract term



12.18 As can be seen, the methodology provides a penalty for longer term contracts compared with shorter contracts.

12.19 The extent of the penalty is determined by the rate at which the contribution to security beyond the needs assessment horizon is discounted. A 10% per annum discounting implies the probability that this is a need is reduced to 60% after 5 years and 35% after 10 years and provides a relatively small penalty. A 20% per annum rate implies the probability is reduced to 33% after 5 years and 11% after 10 years and provides a more significant penalty. The Commission will need to determine the appropriate value.

13. Choosing successful bids

13.1 The methodology above enables an effective levelised cost per MWh for each offer to be calculated. Offers can be ranked according to this criteria and the Commission can choose the cheapest set of offers up to the level of need.

13.2 In practice there may be dependencies between the offers which complicates the selection. For example:

- Some bids may be of a minimum size. It is likely that the Commission will face the choice between one large bid (in excess of the need) and a set of smaller bids. Simple ranking of bids would not necessarily select the cheapest combination of bids;
- Similarly some offers may be mutually exclusive (e.g. a tenderer may offer two different bid alternatives for the same facility);
- The assessed contribution to security may vary depending on the mix of reserve selected.

13.3 The most straightforward way to deal with bid interdependencies is to separately evaluate the relevant combinations of offers and choose the lowest cost set of bids that meets the assessed need. Combinations of offers can be assessed as described above. The number of bids that need to be evaluated in this way may be reduced by establishing some pre-screening tests to eliminate bids that are clearly more costly.

13.4 Although the methodology described above provides a basis for ranking offers of reserve according to cost per unit of reserve provided, it will still be necessary to account for a range of other non-price factors and preferences in the final selection.

14. Simplifying the Evaluation

14.1 The methodology described above will deal with a range of different forms of reserve energy and can account for different pricing structures.

14.2 It can, however, be significantly simplified if certain restrictions are imposed on the offers to make them more comparable.

14.3 Such restrictions could be imposed in different ways:

- All tenderers might be required to offer the same variable cost (or similar) so that the evaluation can focus on the availability fee;
- Alternatively tenderers may be required to select one of a limited set of values – e.g. the demand side could be offered a choice of either a CNS of either 50c or 100c, or the supply-side could be offered a VF of either 20c or 30c.

14.4 A two stage evaluation process might be employed if reserve energy offers are divided into separate classes as was described in section 6 of the report. In this case the ranking of offers within each class can be simplified, however some form of evaluation similar to that described above will be necessary to determine the total amount of reserve to be purchased from each class.

Appendix 4. Example Term Sheet for Reserve Generation

Agreement dated [ ]

between

[Name of Supplier] (Supplier)

and

the Electricity Commission (Commission)

Background

The Electricity Commission is established under the Electricity Act 1992 ("the 1992 Act"), as amended by the Electricity Amendment Act [2004].

The Commission is required to achieve a range of specific outcomes. One is that *"risks (including price risks) relating to security of supply are properly and efficiently managed"*[58].

The Commission also has the function of using *"reasonable endeavours to ensure security of supply (including contracting for reserve energy), without assuming any reduction in demand for emergency conservation campaigns, while minimising distortions to the normal operation of the market"*[59].

In addition, the Government has issued a Government Policy Statement dated [ ] ("the GPS")[60]. Among other things, the GPS requires the Commission buy reserve energy *"as a primary mechanism for the Commission in endeavouring to ensure security of supply in a 1 in 60 dry year"*[61]. The key operational parameters of the reserve energy mechanism are to set out in regulations under the 1992 Act[62].

This Terms Sheet sets out the key terms and conditions on which the Commission proposes to buy reserve energy for the purposes outline above. A detailed form of contract is to be included in the Commission's Request for Proposal.

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58 Section 172N of the 1992 Act

59 Section 172O of the 1992 Act

60 Against which, under 172ZK to 172ZM of the 1992 Act, the Commission's performance is to be assessed and reported. Under section 172O(1)(j) of the 1992 Act, the Commission has the function of giving effect to the GPS

61 Paragraph [ ] of the GPS

62 Paragraph [ ] of the GPS and section 172CA of the 1992 Act

1. Interpretation

1.1 In this Terms Sheets:

(a) “the Commission” includes its agents, contractors and representatives;

(b) “deliver”, “delivered” and “delivery” each includes generation and compliance with all relevant industry rules, regulations and standards, excluding wholesale market requirements covered by Part G of the Electricity Governance Regulations;

(c) “the contract” means a contract entered into by the Commission and the Supplier for the delivery of reserve energy. The key terms and conditions set out in this Term Sheet are intended to provide a basis for the contract; and

(d) Nothing is intended to create legal relations. This Term Sheet is illustrative only.

2. Reserve Energy

2.1 On one week’s notice from the Commission, the Supplier is to deliver:

(a) Up to [ ] MWh over any consecutive [ ] week period within the Availability Period; or at the Commission’s discretion –;

(b) Up to [ ] MWh within the Availability Period;

(c) The Commission may determine the amount of electricity to be produced within these limits;

(d) The Commission requires delivery of this Reserve Energy to a have high degree of reliability.

3. Reserve Capacity *(possible feature for some plant-specific reserve energy contracts)*

The Supplier is to keep available [at all times] during the Availability Period no less than [ ] MW of generation capacity [at a certain station] to produce Reserve Energy.

4. Availability Period

4.1 In [year], this is the period from [date] to [date];

4.2 In [year], this is the period from [date] to [date];

4.3 In [year], this is the period from [date] to [date];

(Covering the relevant periods for managing dry risk during the term of the contract)

5. Dispatch and Sale

5.1 Except for Distribution Network Load Management, only the Commission may dispatch Reserve Energy during the Availability Period.

5.2 Any dispatch of Reserve Energy by the Commission is to be consistent with:

(a) Its Dispatch Policies *(to be annexed to the contract)*, which the Commission is to establish (and may vary from time to time) to reflect:

(i) the requirements of the GSP in relation to reserve energy;

(ii) any regulations made under the 1992 Act or any other legislation in relation to reserve energy; and

(iii) other policies developed and published by the Commission to implement its responsibilities in relation to security of supply under the Act, GSP or any other relevant statutes, regulations, rules or industry standards; and

(b) The protocols established and published by the Commission under paragraph [47] of the GPS *(which requires the Commission to put in place protocols to manage potential conflicts between its role as a participant in the market and as a regulator).*

5.3 For the avoidance of doubt, the Commission may dispatch Reserve Energy to help cope with unexpected supply contingencies such as serious grid, plant, or fuel supply disruptions.

6. The Commission is responsible for complying with, and meeting all costs relating to, Part G of the Electricity Governance Regulations 2003 in relation to Reserve Energy.

7. Ownership and Sales Revenues

All Reserve Energy, and all revenues received from its sale, is the property of the Commission.

8. Fuel Supply

8.1 The Supplier is to establish and maintain at its expense fuel supply arrangements necessary to ensure that all Reserve Energy is delivered in accordance with the contract. In particular (but without limitation), the Supplier is to:

(a) Maintain sufficient fuel stocks on-site to enable a minimum period of continuous running of [ ] hours producing no less than [ ] MWh;

(b) Have contracts in place that ensure the replenishment of on-site storage to enable continuous running of up to [ ] months; and

(c) Provide proper systems and procedures to ensure that on-site fuel quality is maintained to the required quality standards.

9. Maintenance

9.1 The Supplier will maintain at its expense all plant, equipment and systems necessary to ensure the delivery of Reserve Energy in accordance with the contract.

9.2 Planned maintenance will be undertaken at a time agreed between the Supplier and the Commission at least six months prior to any planned maintenance period.

10. Testing

10.1 At its expense and at the Commission's request, the Supplier will carry out up to [ ] test runs each year to demonstrate that relevant plant, equipment and systems are capable of delivering the Reserve Energy in accordance with the contract.

10.2 The Supplier will report to the Commission in writing on the results within [ ] days of each tests.

10.3 The Commission may observe or oversee each test.

10.4 The Commission's remedies if the Supplier fails to meet any of these testing requirements include an obligation on the Supplier to ensure, urgently and at its expense, that all problems causing the failure are remedied within a timetable and to a confidence level satisfactory to the Commission.

11. Inspection

The Commission may inspect up to [ ] times each year [at the Supplier's expense] all plant, equipment, systems, fuel stocks, fuel supply contracts, maintenance records, operational records and other factors relevant to the delivery of Reserve Energy in accordance with the contract.

12. Reporting

The Supplier is to report to the Commission every month on the availability and readiness of all plant, equipment, fuel stocks, fuel contracts, systems and other factors relevant to the delivery Reserve Energy in accordance with the contract.

13. Compliance with Regulations and Rules

The Supplier is responsible for complying with, and meeting all costs relating to, all regulations, rules and industry standards relevant to the delivery of Reserve Energy, except for Part G of the Electricity Governance Regulations 2003.

14. Measurement and Invoicing

14.1 Using appropriate metering systems, the Supplier is to measure the amount of Reserve Energy delivered over a [weekly/monthly] period and invoice the Commission for this amount on a monthly basis.

14.2 The Commission may at any time verify the amount of Reserve Energy delivered in accordance with the contract.

15. Agency

15.1 The Commission may appoint an agent or representative to carry out any of its responsibilities under the contract.

15.2 The Commission is to advise the Supplier in writing of any agents or representatives the Commission appoints under the contract.

15.3 The Supplier may not appoint any agent or representative to carry out its responsibilities under the contract without the Commission's prior written approval.

16. Distribution Network Load Management ("DNLM")

16.1 If the Reserve Energy is produced by generation facilities located within a local distribution network, Reserve Energy may be dispatched by the Supplier to assist in managing loads on the local distribution network ("DNLM purposes") if:

(a) Commission advises the Supplier in advance that the Reserve Energy to be dispatched is not required by the Commission;

(b) The total amount of Reserve Energy used for DNLM purposes does not exceed [ ] MWh over a [ ] month period; and

(c) The Supplier reports to the Commission in writing every month with the amount of Reserve Energy dispatched by the Supplier and certifies that it was used for DNLM purposes.

17. Payment

17.1 The Commission will pay the Supplier:

(a) An Availability Fee at a rate of [$] per month, provided that the full amount of Reserve Energy is ready to be delivered.

(b) A Variable Fee at a rate of [$] per MWh of Reserve Energy delivered.

18. Penalties

18.1 Failure to deliver Reserve Energy following a dispatch instruction from the Commission will incur penalties payable by the Supplier to the Commission.

18.2 Penalties are to be calculated on a weekly basis and invoiced each month.

18.3 Penalties accrue on non-delivered Reserved Energy at the higher of 20c/kWh and either the Variable Fee or the average spot price during the period of non-delivery, whichever is lower.

18.4 The Supplier’s total liability for penalties [in any year] is limited to [ ]

19. Bonuses

19.1 The Commission is to pay the Supplier bonuses for electricity delivered during the Availability Periods by the Supplier on instructions from the Commission in excess of the amounts set out in clause 1.

19.2 The bonuses are to be calculated on a weekly basis and invoiced by the Supplier each month.

19.3 Bonus payments accrue at a rate of [ ] per MWh of electricity delivered during the Availability Periods by the Supplier on instructions from the Commission in excess of the amounts set out in clause 1.

19.4 Over any month, bonuses may be offset against penalties.

20. Force Majeure

20.1 The Supplier is not liable to the Commission for failure to perform the contract only if the failure is the result of circumstances that:

(a) are not reasonably foreseeable (excluding the risk of low hydro inflows) and

(b) could not have been mitigated or avoided if the Supplier exercised its best endeavours, taking into account the importance of the reserve generation in managing a 1 in 60 dry period.

21. Term

The contract commences on [date] and comes to an end on [date].

22. Termination

22.1 Either party may terminate the contract in the event of persistent breach of the contract by the other party.

22.2 The Commission may terminate the contract by payment of an agreed net present value of the remainder of the contract.

Appendix 5. Example Term Sheet for Reserve Demand

Agreement dated [ ]

between

[Name of Supplier] (Supplier)

and

the Electricity Commission (Commission)

Background

The Electricity Commission is established under the Electricity Act 1992 ("the 1992 Act"), as amended by the Electricity Amendment Act [2004].

The Commission is required to achieve a range of specific outcomes. One is that *"risks (including price risks) relating to security of supply are properly and efficiently managed"*[63].

The Commission also has the function of using *"reasonable endeavours to ensure security of supply (including contracting for reserve energy), without assuming any reduction in demand for emergency conservation campaigns, while minimising distortions to the normal operation of the market"*[64].

In addition, the Government has issued a Government Policy Statement dated [ ] ("the GPS")[65]. Among other things, the GPS requires the Commission buy reserve energy *"as a primary mechanism for the Commission in endeavouring to ensure security of supply in a 1 in 60 dry year"*[66]. Reserve energy includes contracted demand responses[67]. The key operational parameters of the reserve energy mechanism are to set out in regulations under the 1992 Act[68].

This Terms Sheet sets out the key terms and conditions on which the Commission proposes to buy reserve energy for the purposes outline above. In this terms sheet,

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63 Section 172N of the 1992 Act

64 Section 172O of the 1992 Act

65 Against which, under 172ZK to 172ZM of the 1992 Act, the Commission's performance is to be assessed and reported. Under section 172O(1)(j) of the 1992 Act, the Commission has the function of giving effect to the GPS

66 Paragraph [ ] of the GPS

67 Paragraph [ ] of the GPS

68 Paragraph [ ] of the GPS and section 172CA of the 1992 Act

reserve energy is an agreed quantity of demand savings. A detailed form of contract is to be included in the Commission's Request for Proposal.

1. Interpretation

1.1 In this Terms Sheets:

(a) "the Commission" includes its agents, contractors and representatives;

(b) "deliver", "delivered" and "delivery" refer to making or procuring objectively verifiable savings in electricity consumption;

(c) "dispatch" includes calling for delivery;

(d) "the contract" means a contract entered into by the Commission and the Supplier for the delivery of reserve energy. The key terms and conditions set out in this Term Sheet are intended to provide a basis for the contract; and

(e) Nothing is intended to create legal relations. This Term Sheet is illustrative only.

2. Reserve Energy

2.1 On [ ] days/hours notice from the Commission, the Supplier is to reduce electricity consumption at a specified meter by a specified amount ("the Contracted Reduction") relative to a specified benchmark demand level ("the Benchmark Demand Level") during a specified period ("the Availability Period"). *(Note - an Availability Period may be a week, a month or longer during the season relevant to managing dry year risk)*

2.2 The Contracted Reduction ("CR") and Benchmark Demand Level ("BDL") for each Availability Period covered by the contract:

(a) Will be set out in a schedule to the contract; and

(b) At the Commission's discretion, may be reviewed and amended [ ] in advance of the Availability Period.

2.3 In this Terms Sheet, Reserve Energy means the CR measured against the BDL for the relevant Availability Period.

2.4 The Commission requires a high degree of reliability in the delivery of Reserve Energy.

3. Dispatch

3.1 Only the Commission may dispatch Reserve Energy during the Availability Period.

3.2 Any dispatch of Reserve Energy by the Commission is to be consistent with:

(a) Its Dispatch Policies *(to be annexed to the contract)*, which the Commission is to establish (and may vary from time to time) to reflect:

(i) the requirements of the GSP in relation to reserve energy;

(ii) any regulations made under the 1992 Act or any other legislation in relation to reserve energy; and

(iii) other policies developed and published by the Commission to implement its responsibilities in relation to security of supply under the Act, GSP or any other relevant statutes, regulations, rules or industry standards; and

(b) The protocols established and published by the Commission under paragraph [47] of the GPS *(which requires the Commission to put in place protocols to manage potential conflicts between its role as a participant in the market and as a regulator).*

3.3 For the avoidance of doubt, the Commission may dispatch Reserve Energy to help cope with unexpected supply contingencies such as serious grid, plant, or fuel supply disruptions.

4. Maintenance

The Supplier will maintain at its expense all equipment and systems necessary to ensure the delivery of Reserve Energy in accordance with the contract.

5. Testing

5.1 At its expense and at the Commission's request, the Supplier will carry out up to [ ] test runs each year to demonstrate that relevant equipment and systems are capable of delivering the Reserve Energy in accordance with the contract.

5.2 The Supplier will report to the Commission in writing on the results within [ ] days of each tests.

5.3 The Commission may observe or oversee each test.

5.4 The Commission's remedies if the Supplier fails to meet any of these testing requirements include an obligation on the Supplier to ensure, urgently and at its expense, that all problems causing the failure are remedied within a timetable and to a confidence level satisfactory to the Commission.

6. Inspection

The Commission may inspect up to [ ] times each year at the Supplier's expense all equipment and systems, contracts, records and other factors relevant to the delivery of Reserve Energy in accordance with the contract.

7. Reporting

The Supplier is to report to the Commission every month during an Availability Period on the readiness to deliver the Reserve Energy in accordance with the contract.

8. **Compliance**

The Supplier is responsible for complying with, and meeting all costs relating to, any regulations, rules and industry standards relevant to the delivery of Reserve Energy.

9. Measurement and Invoicing

9.1 Using agreed meters, the Supplier is to measure the amount of Reserve Energy delivered over a [weekly/monthly] period and invoice the Commission for this amount on a monthly basis.

9.2 The Commission may at any time verify the amount of Reserve Energy delivered in accordance with the contract.

10. Agency

10.1 The Commission may appoint an agent or representative to carry out any of its responsibilities under the contract.

10.2 The Commission is to advise the Supplier in writing of any agents or representatives the Commission appoints under the contract.

10.3 The Supplier may not appoint any agent or representative to carry out its responsibilities under the contract without the Commission's prior written approval.

11. Payments

11.1 The Commission is to pay the Supplier:

(a) An Availability Fee at the rate of [$] per month, provided that the full amount of Reserve Energy is ready to be delivered; and

(b) A variable amount for each KWh of Reserve Energy delivered. On entering into the contract, the Supplier is to choose a rate which is either:

(i) [$] per KWh of delivered Reserve Energy ("the Variable Fee"); or

(ii) The Variable Fee ("VF") less the average wholesale spot price during the period in which the Reserve Energy was delivered ("the SP"); except that if the SP is greater than the VF, the Supplier will receive no payment from the Commission for each KWh of Reserve Energy delivered.

12. Penalties

12.1 If the Supplier fails to deliver all of the Reserve Energy dispatched by the Commission, the Supplier will pay the Commission penalties on the shortfall at a rate equal to:

(a) 20c per KWh; or

(b) The lower of VF and SP –

– which ever of (a) and (b) above is the higher.

12.2 Penalties are to be calculated on a weekly basis and invoiced each month.

12.3 The Supplier's total liability for penalties in any year is limited to [500 hours multiplied by the VF multiplied by the Reserve Energy expressed in average MW for the relevant year].

13. Bonuses

13.1 If the Supplier delivers demand reductions in excess of the Reserve Energy dispatched by the Commission, the Commission will pay the Supplier bonuses on the additional quantity at a rate equal to:

(a) 50% of VF, if Supplier elected (b) (i) under clause 11

(b) 50% of the maximum of (VF minus SP) and zero, if the Supplier elected (b) (ii) under clause 11 .

13.2 The bonuses are to be calculated on a weekly basis and invoiced by the Supplier each month.

13.3 Over any month, bonuses may be offset against penalties.

14. Change of Circumstances

14.1 The Supplier is to notify the Commission without delay of any change in circumstances that could affect its delivery of Reserve Energy.

14.2 Any notification of this kind will not diminish the Supplier's obligations under the contract.

14.3 The Supplier will, urgently and at its expense, put in place alternative arrangements to ensure that it can deliver Reserve Energy in accordance with the contract.

15. Force Majeure

15.1 The Supplier is not liable to the Commission for failure to perform the contract only if the failure is the result of circumstances that:

(a) are not reasonably foreseeable (excluding the risk of low hydro inflows) and

(b) could not have been mitigated or avoided if the Supplier exercised its best endeavours, taking into account the importance of the reserve generation in managing a 1 in 60 dry period.

16. Term

The contract commences on [date] and comes to an end on [date].

17. Termination

17.1 Either party may terminate the contract in the event of persistent breach of the contract by the other party.

17.2 The Commission may terminate the contract by payment of an agreed net present value of the remainder of the contract.

Appendix 6. A possible small customer reward-savings scheme

1. Previous Reward Savings Schemes

1.1 During previous electricity shortages Dunedin Electricity (1992) and Mighty River Power (2001 and 2003) have offered reward-savings schemes to small customers in an attempt to reduce small customer energy consumption and avoid more costly interventions or rationing.

1.2 During 2001, Mighty River Power offered 200,000 mass market customers a price rebate of 5¢ per KWh for energy saved over a two month period.[69] When combined with the saving on the normal tariff this equated to a saving for each customer of 17¢ per KWh saved. Mighty River Power estimated that over 50GWh of energy was saved and $2.0m in rebates was paid, in aggregate, to more than 60% of customers.

1.3 In order to calculate the rebates, we understand that Mighty River Power established a simple benchmark for each customer based on the previous winter's electricity consumption.

[69] In the time available we have not been able to establish exactly what was offered by Dunedin Electricity (in 1992) and Mighty River Power (in 2003).

2. A possible Commission sponsored arrangement

2.1 The concept of a reward-savings scheme involves retailers offering contracts to customers that include a provision to reward electricity savings according to a fairly simple mechanism. The role of the Commission and retailers in an illustrative arrangement are outlined in the following table.

2.2 This illustrative arrangement would involve an administrative overhead for retailers who participated in the scheme. The overhead would include confirming benchmarks for each customer, securing agreement to the contract, and making payments wherever the energy savings are called by the Commission. To compensate for these costs the illustration involves the Commission paying each retailer a per customer fee.

2.3 It is not envisaged that the payments to individual small customers would need to be funded by the Commission. This is because the retailers are likely to benefit from the savings through lower payments through the spot market.

Table 6: Illustrative Small Customer Reward-Savings Scheme

Electricity Commission	Retailer
• Agrees to pay retailers an annual fee for each customer that agrees to a "reward savings" contract • Sets basis for benchmarking customer demand against which savings are to be measured • Sets price to be paid for energy saved • Triggers energy savings when security is at risk as part of "merit order" of energy reserves	• Agrees to offer "reward savings" contracts to small customers • Confirms energy saving relative to benchmark for each customer • Pays each customer the agreed price for energy saved

2.4 Several variants of this arrangement are possible including:

- The Commission running a tender amongst retailers in order to achieve the lowest cost per customer
- Retailers agreeing, by contract, to achieve a target level of demand reductions in order to provide more confidence on the level of savings likely to be achieved.

Appendix 7. Key Terms Used in Security of Supply Reports

Term (in context of this paper)			Section
1 in 60 dry year		A year in which there is a hydro drought of the severity that can be expected to occur every 60 years. The duration and timing of such an event will determine whether it has implications for security of supply.	PD[70]4.1.1
Additionality		A key concept raised in the GPS - it states that reserve energy should "provide additional security of supply beyond the level achieved by the ordinary market."	8, 10
Alternative Measures		A separate work stream that the Commission has in-train to consider longer term options to enhance arrangements and incentives relating to its security of supply objectives.	1
Availability Fee (AF)		A fee that notionally covers the fixed costs of supplying the reserves	4, 9, 10, 11, 12
EGIB		Electricity and Gas Industries Bill (http://www.med.govt.nz/ers/electric/supply-security/ris-bccs/bill/index.html) – superseded by the Electricity Amendment Act	PD5
Emergency measures		Provisions which the Commission may need to trigger in a situation worse than a 1 in 60 dry to avert energy shortages (for example, a conservation campaign).	PD9.4
Energy margin		The amount of additional electricity demand growth (in %) that could be supplied in a 1 in 60 dry year, given a particular hydro/ fuel starting storage position	PD6.5
ESA		Energy Security Assessment – a technique proposed in this paper whereby the Commission would produce security of supply risk assessments over various timeframes	PD6.4.2, 6.5, 2.4

[70] Reference to section in Security of Supply Policy Development Discussion Paper

Term (in context of this paper)			*Section*
Expected demand		In the context of this paper, the estimated electricity demand during a 1 in 60 year hydro drought taking into account normal market responses to the spot prices	PD4.1.2
Expected supply		In the context of this paper, the estimated technical generation capability of the electricity supply system in a 1 in 60 year hydro drought.	PD4.1.3
GPS		Government Policy Statement (http://www.med.govt.nz/ers/electric/governance-gps/index.html)	PD5
Expected Unserved Energy (EUE)		A statistical estimate of the mean amount of energy shortage that is expected to occur over a given period of time (typically a year).	PD4.3.3
Loss of Load Probability (LoLP)		A statistical estimate of the expected duration of energy shortages in given period of time, typically a year.	PD4.3.2
Minzone		The profile of minimum hydro storage levels throughout the year at which the electricity supply system could cope with a 1 in 60 hydro drought from that point forward without the need for emergency demand conservation measures. It represents the technical supply capability of the system in a 1 in 60 dry year.	PD6.3
Needs Assessment		The process of assessing security of supply looking out 3 to 5 years and determining the quantity of reserve energy required in that timeframe.	8
Reserve energy		Electricity generation or demand reductions which the Commission is able to procure through contracts so as to increase the level of security delivered by the normal electricity market to the 1 in 60 dry year standard. Procurement is limited to 1,200GWh in any 4 month period. This is different to instantaneous reserves (spinning reserves or interruptible load) used in the market for real time system security.	PD5.2, 5.3

Term (in context of this paper)			Section
Return period		The statistical frequency which a particular event can be expected to recur.	
Tight ring-fencing		A key concept raised in the GPS where initially, at least, reserve energy may only be used for meeting security of supply objectives, with a view to ensuring that distortions to the ordinary market are minimised.	8, 9, 10
Security guidelines		Hydro storage profiles (similar to the minzone) representing different levels of security risk. Guidelines below the minzone would correspond to increasing risk of energy shortage. Each guideline would represent a constant risk throughout the year.	PD9.3
Security margin		See energy margin	
Security of supply		The physical ability of the electricity supply system to meet electricity demand.	
Thermal margin		The amount of thermal supply (in %) that could be lost in a 1 in 60 dry year, given a particular hydro/ fuel starting storage position, and still be able to meet *expected demand*	PD6.5
TWD or Tail Water Depressed Spinning Reserves		Hydro generating units which can force water out of the turbine casing so that the generating units can be connected to the grid and operated as motors. These units are able to switch relatively quickly to generating mode if an under frequency event occurs on the grid.	PD8.8.2
Variable Fee (VF)		A fee that notionally covers the supplier's variable costs of providing reserve energy	4, 9, 10, 11, 12
VoLL		The estimated *value of lost load*. This concept is commonly used in electricity markets to represent the implied cost to consumers of losing supply. For the purpose of this paper, VoLL has been estimated at approximately $8,000/MWh (or $8.kWh) based on the 1 in 60 dry year policy requirements in the GPS.	PD9.2