Consultation Paper

Scarcity Pricing – Proposed Design

Prepared by the Electricity Authority
28 March 2011

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1 Scarcity Pricing – Proposed Design

1.1 Executive summary

1. The Electricity Authority ('Authority') is progressing a number of priority projects to improve the performance of the electricity market. The possible introduction of scarcity pricing is one of these projects.

2. Scarcity pricing is designed to address concerns that spot prices are likely to be suppressed during supply emergencies, due to the use of non-price rationing mechanisms such as forced load shedding. The mechanisms used to deal with supply emergencies can take different forms, depending on whether the emergencies reflect a shortage of generation *capacity* in the immediate period or insufficient *energy and/or fuel* supply to meet projected demand over coming weeks or months.

3. Most emergencies can be resolved using the less severe measures, but in some cases conditions may deteriorate to a point where more severe measures are required. The different types of supply emergencies and possible response mechanisms are summarised in Table 1.

Table 1: Types of supply emergency and non-price response mechanisms

Generation capacity shortage in real time	**Instantaneous reserve shortfall** (less severe)	**Emergency load shedding** (more severe)
Energy/fuel shortage over coming periods	**Public conservation campaign** (less severe)	**Rolling outage load shedding** (more severe)

Declining frequency of occurrence

4. In all cases, these response mechanisms invoked during emergencies involve a non-price intervention which reduces security or demand below normal levels, and which imposes costs or risks on electricity users. Under current arrangements, these costs or risks may not be recognised when spot prices are calculated.

5. It is important that spot prices during supply emergencies provide efficient signals. Otherwise it will undermine efficient investment in last resort generation and/or voluntary demand side response.

6. This will lead to an over-reliance on non-price mechanisms such as forced load shedding and public conservation campaigns, both of which impose a cost on consumers. It is important these measures are not over-used, as they increase the likelihood of ad-hoc regulatory intervention during or after a supply emergency, which tends to further undermine investor confidence.

7. In summary, the incentive for efficient investment will be undermined and there will be increased risk of forced rationing. This outcome would be detrimental to the long term interests of consumers.

8. In principle, the concerns noted above could be addressed by ensuring that all classes of electricity user can react to and influence spot prices – as typically occurs in markets for other products. This would allow each user to select the level of security that it is willing to pay for. The resulting market price should better reflect users' overall preferences about the trade-off between cost and reliability. It should also ensure that available supply is allocated to those parties who place the highest value on continued usage.

9. While the Authority is pursuing initiatives to improve the scope for demand side participation in the wholesale electricity market[1], it is important to acknowledge that there are significant technological and transaction cost barriers in this area. In particular, if mandatory load shedding is required in an emergency, it is not practical to selectively disconnect users according to their individual security/price preferences.

10. Although the level of demand-side participation is expected to grow, the inability of most users to directly signal their preferences in supply emergencies is expected to remain for some time. This means that the potential for price suppression during supply emergencies will continue.

1.1.1 Proposed measures

11. The initiatives being proposed by the Authority are intended to address the concerns set out above. In broad terms, the initiatives would alter the way that spot prices are determined during certain types of supply emergency to reduce the risk of spot price suppression. In the case of public conservation campaigns, two possible approaches are being considered. Table 2 summarises the proposed changes.

Table 2: Core elements

Situation	Proposal
Instantaneous reserve (IR) shortfalls	Modify the pricing process to reduce the scope for price suppression or unduly high spot prices (many multiples of the highest supply offer) when spot prices are close to infeasibility
Emergency load shedding	Apply a floor to spot prices when emergency load shedding is applied The floor would be $10,000/MWh (once transition is complete)
Public conservation campaigns	Apply a floor to spot prices when a public conservation campaign is running and the risk of shortage is 10% or higher. The floor would be $500/MWh (once transition is complete) And/or Require wholesale market participants to regularly disclose their net spot market exposure to the Authority. The Authority would prepare a summary report which could be released. The summary would provide sufficient information to indicate which parties would be expected to benefit financially from public conservation campaigns

[1] For example the proposal to allow qualifying demand sources to be dispatched in a manner similar to generation, and the proposed changes to demand side bidding and forecasting arrangements.

Rolling outage load shedding	Apply a floor to spot prices when rolling outage load shedding is applied The floor would be $3,000/MWh (once transition is complete)
Other issues	Scarcity price floors would only apply to shortages that affect one or both islands (i.e. not for more localised shortages). Similarly, floor prices would not apply in any trading periods that are not affected by shortage

1.1.2 Transition arrangements

12. Scarcity pricing would be a significant change to current arrangements, and a phased transition appears desirable. This would help participants to progressively gain experience with new arrangements, and assist in ensuring that participants are able to be highly hedged by the time scarcity pricing is fully introduced. This should increase the overall durability of the regime.

13. The Authority has considered three possible forms of transition:

    (a) staging the introduction of the measures, focusing first on capacity-related measures (i.e. the price floor for emergency load shedding and IR changes) and the disclosure requirements;

    (b) introducing the whole package of changes (including disclosure), but increasing the value of the scarcity price floors over a transition period; and

    (c) introducing the whole package (including disclosure) with full scarcity price values, but moderating the impact of price floors with a 'stop-loss' type mechanism that is progressively relaxed over time.

14. If (b) or (c) is adopted, the transition profile for scarcity price values or the cumulative price threshold could be specified in detail. Alternatively, a set of initial values could be defined, with subsequent changes being contingent upon further assessment by the Authority. The second approach would give the Authority greater scope to 'ratchet up' the effect of scarcity pricing as hedge market activity increases.

15. It would also be possible to combine aspects of the approaches outlined above. For example, it would be possible to proceed first with the capacity-related and disclosure measures, but to increase the scarcity price floor for emergency load shedding over time.

16. At this point, the Authority does not have any firm preference in relation to transition arrangements. A key issue in selecting the path forward will be the perceived effect on the durability and credibility of scarcity pricing arrangements. The Authority is conscious that these factors will be very important for scarcity pricing to have the desired enduring effect on incentives.

17. In weighing the various options, the Authority's objective is to identify the overall package of changes that will move electricity market arrangements toward the

desired goal as swiftly as possible, while minimising the risk of ad-hoc intervention in a supply emergency. Obtaining stakeholder views on these matters will be very important in identifying the package of measures that best balances these various considerations.

1.1.3 Other changes to wholesale market

18. The Authority is progressing a number of other changes to the wholesale market alongside scarcity pricing. These include:
    - the introduction of a dispatchable demand product – to increase the potential for demand-side participants to 'contest' with generation in the wholesale market;
    - changes to demand-side bidding and forecasting arrangements which should improve pre-dispatch price signals and facilitate competition and demand-side response;
    - the introduction of an inter-island locational hedge product to facilitate hedging of locational price risk;
    - a review of settlement and prudential arrangements to ensure they achieve an appropriate balance between the financial security of the market (the confidence that there will be sufficient money available to pay generators) and the promotion of competition by encouraging new entry into the retail market; and
    - encouraging the development of a more liquid energy hedging market.
19. These changes should complement scarcity pricing, because they will facilitate the use of hedging instruments, and/or improve the scope for demand side participation. Both types of initiative are important because they broaden the options available to manage spot price risk. Ensuring that participants have reasonable means to manage their risk exposures will be important for scarcity pricing to be durable over time.
20. The Authority has also considered whether specific price capping mechanisms should be introduced alongside these proposed changes. The Authority is concerned that price capping mechanisms could have unintended adverse consequences.
21. The Authority considers that concerns about weak competition are more appropriately addressed by pro-competitive measures and enhanced market monitoring. In respect of the potential for high spot prices during exceptional unforeseeable events (e.g. a major natural disaster), the Authority believes this can be adequately addressed through existing provisions relating to undesirable trading situations.
22. In light of these factors the Authority considers that permanent price capping mechanisms should not be introduced as part of the proposed implementation of scarcity pricing. The Authority, however, is considering whether a temporary cumulative price threshold on scarcity prices would be a suitable instrument for transitioning to a scarcity pricing regime.

1.1.4 Assessment of proposed changes

23. Scarcity pricing is expected to have two offsetting impacts. Relative to the status quo (with some suppression of spot prices in supply emergencies), some upward pressure is expected in the overall cost of supply. However, scarcity pricing is also expected to improve security, resulting in a lower level of forced demand curtailment (and associated cost) over time. It is the net effect of these opposing influences that is important when considering the long term interests of electricity consumers.

24. A quantitative cost benefit analysis has been undertaken of the proposed changes listed in Table 2. The changes are estimated to have potential net economic benefits of approximately $95 million to $114 million when assessed against the counter-factual. Even if a more conservative counter-factual (with less price suppression) is assumed, the expected potential net benefit range remains positive at approximately $19 million to $24 million. Importantly, these results are based on an assumption that scarcity pricing changes are durable and are perceived as such by market participants. To the extent that this assumption does not hold, the net benefits of the proposals would decline and could even be negative.

25. Based on current information, the Authority considers that the proposals are potentially consistent with its statutory objective.

26. The Authority is also mindful there are other measures that could complement scarcity pricing, relating primarily to hedging market arrangements. At this point, the Authority considers that the proposals in Table 2 (with some transition arrangement) are a good starting point and it will observe hedging behaviour to determine whether to consider additional measures to achieve robust security of supply arrangements and management of market risks.

1.1.5 Next steps

27. The Authority seeks views from submitters on the issues set out in this paper. This feedback will be taken into account by the Authority in the next phase of work.

28. This work is expected to include the preparation of a detailed design proposal which will include proposed Code amendments. It is expected that this will be released for consultation in mid-2011. Final decisions on scarcity pricing proposals are expected in the third quarter of 2011, so that any resulting Code changes can be made by 1 November 2011.

29. To assist parties in this phase of the process, the Authority will host a briefing session before the submission closing date on the scarcity pricing proposals contained in this paper. The specific details for this briefing session will be posted on the Authority's website shortly.

30. In addition, the Authority will shortly be releasing a relatively brief 'plain English' companion document which provides an overview of scarcity pricing for the non-technical reader.

31. While the companion document provides a summary the proposals being considered by the Authority, parties wishing to make submissions should nonetheless refer to this full Consultation Paper because this sets out the proposals in detail.

1.2 Glossary

Act	Electricity Industry Act 2010
AUFLS	Automatic under frequency load shedding
CNS	Cost of non-supply
Code	Electricity Industry Participation Code
CPT	Cumulative price threshold
DSM	Demand side participation
FIR	Fast instantaneous reserve
FTR	Financial transmission right
GWh	Gigawatt hour
HVDC	High voltage direct current link between the islands
IL	Interruptible load
IR	Instantaneous reserve
kW	Kilowatt (1,000 watts)
MCE	Market clearing engine
MW	Megawatt (1 million watts)
NFR	Net free reserve
NI	North Island
OCGT	Open cycle gas turbine
PCC	Public conservation campaign
RAF	Reserve adjustment factor
RT	Real time
SI	South Island
SIR	Sustained instantaneous reserve
SPD	Scheduling, pricing and dispatch model
SPTG	Scarcity Price Technical Group
TP	Trading period

VoLL	Value of lost load
WCM	Winter capacity margin
WEM	Winter energy margin

2 Contents

3 Introduction and purpose of this paper

3.1 Introduction

32. The Authority is progressing a number of priority projects intended to improve the performance of the electricity market. The proposed introduction of scarcity pricing is one of these projects, and is focussed on improving security of supply incentives. Scarcity pricing is also one of the specific new matters to be covered in the Code by 1 November 2011, as required by section 42(2) of the Electricity Industry Act 2010.

33. The proposals described in this paper build on earlier work undertaken by the Electricity Commission. The Electricity Commission concluded that existing arrangements have some weaknesses in relation to security of supply. It concluded that these could be addressed by improving price signals during supply emergencies (‘scarcity pricing’) or by introducing some form of compulsory contracting. The Electricity Commission released a consultation paper[2] which recommended that the former option be progressed to a working design. Submissions were received from a range of parties, and these generally supported the proposed approach.

34. The Scarcity Pricing and Default Buyback Technical Group (SPDBTG)[3] was established in March 2010 to provide advice on the development of a working design for scarcity pricing arrangements.

3.2 Purpose of this paper

35. The purpose of this paper is to consult with participants and persons that the Authority thinks are likely to be substantially affected by the proposed introduction of scarcity pricing.

36. The Authority invites feedback on the proposals discussed in this paper. This feedback will be taken into account in the next phase of work on scarcity pricing issues.

37. This is expected to include the preparation of a detailed design proposal which will include the form of proposed Code amendments. It is expected that this will be released for consultation in mid-2011. Final decisions on scarcity pricing proposals are expected in the third quarter of 2011, so that any resulting Code changes can be made by 1 November 2011 (noting that actual implementation may be phased in over time).

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2 See “Scarcity Pricing and Compulsory Contracting: Options”, *Electricity Commission*, October 2009.

3 Now referred to as the Scarcity Pricing Technical Group (SPTG) as work on a compulsory compensation scheme (formerly referred to as a default buyback mechanism) has been completed.

3.3 Submissions

38. The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with Consultation Paper — Scarcity Pricing Options in the subject line.

39. If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to either of the addresses provided below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

or

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860
Fax: 0-4-460 8879

40. Submissions should be received by 5:00 pm on 29 April 2011. Please note that late submissions are unlikely to be considered.

41. The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

42. If possible, submissions should be provided in the format shown in Appendix A.

43. Your submission is likely to be made available to the general public on the Authority's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

4 What is the underlying problem?

Section summary

- The various mechanisms used to manage supply emergencies have a tendency to suppress spot prices.
- Over time, price suppression is likely to lead to inadequate provision of last resort generation and/or voluntary demand side response – both in an operational ‘real-time’ context, and from a longer-term investment perspective.
- This will lead to an over-reliance on forced load shedding and public conservation campaigns, both of which impose costs on consumers. It is important that these measures are not over-used.

4.1 Suppression of spot prices during supply emergencies

44. As discussed in Section 4.2, it is important that spot prices properly signal the value of electricity to consumers during supply emergencies – otherwise security will be compromised.

45. Supply emergencies can take different forms, depending on whether they reflect a shortage of generation *capacity* in the immediate period or insufficient *energy and/or fuel* supply to meet projected demand over coming weeks or months. They also differ in severity, depending on whether the emergency can be managed without forced load shedding. In some cases, an emergency may start with the less severe measures (IR shortfalls or public conservation campaigns) and deteriorate to a point where the more severe measures (emergency load shedding and rolling outages respectively) are required.

46. The different types of emergency are summarised in Table 3. In all cases, the emergencies involve an administrative or non-price intervention to reduce security or demand below normal levels.

Table 3: Types of supply emergency and non-price response mechanisms

Generation capacity shortage in real time	**Instantaneous reserve shortfall** (less severe)	**Emergency load shedding** (more severe)
Energy/fuel shortage over coming periods	**Public conservation campaign** (less severe)	**Rolling outage load shedding** (more severe)

Declining frequency of occurrence

47. The current arrangements for determining spot prices in supply emergencies have some weaknesses. In particular, spot prices during supply emergencies tend to be suppressed due to the use of non-price mechanisms to ration demand[4]. The following sections outline the pricing issues that can arise under different types of rationing mechanisms.

4.1.1 Emergency load shedding – capacity shortage

48. A capacity shortage refers to a situation where there is insufficient generation to meet demand in the immediate period. This could arise due to inadequate investment in generation capacity, or because some power stations are not available due to breakdowns or because expected returns were insufficient to offset start-up costs.

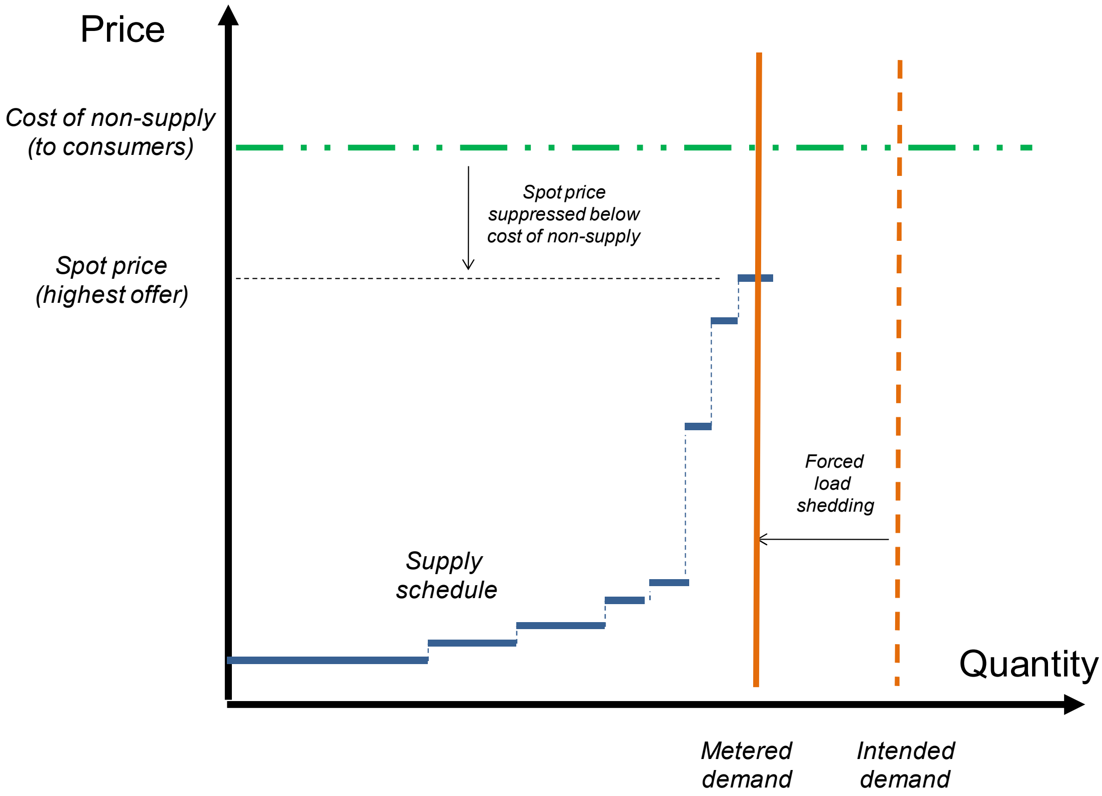
49. Figure 1 illustrates in simplified form how spot prices during a capacity shortage would be determined under current arrangements. All available generator offers have been stacked to form a supply schedule, from least cost to the most expensive. In the normal course of events, spot prices are determined by the intersection of the demand and supply schedules, i.e. spot prices are based on the generator offer price required to meet the last increment of demand[5]. However, there is insufficient generation capacity available for the supply schedule to intersect with *intended* demand.

[4] This includes restricting the 'demand' for instantaneous reserve cover.

[5] This explanation simplifies some issues. For example, there is no single spot price for wholesale electricity, as the market clearing engine (MCE) calculates spot prices for each injection and offtake point on the grid. These prices take account of transmission losses and constraints. However, the key point holds that spot prices are determined using generator offers as a key input.

50. From a physical perspective, if actual demand were to exceed actual supply, this would lead to system collapse[6]. To avoid this, demand must be reduced to the available level of supply by forced load shedding. This effectively moves the demand schedule to the left.

Figure 1: Spot price formation during forced load shedding (illustrative)



51. Instructions to shed load must be issued ahead of real time, and will inevitably be based on imperfect information. Furthermore, the consequences of any misjudgements about requested load shedding are asymmetric. Instances of too *much in*structed load shedding will be hard to clearly identify, but insufficient instructed load shedding would lead to widespread and costly uncontrolled shedding in real time[7]. It is also important to recognise instructed load shedding does not provide for a fine degree of control. As a result, if instructed load shedding is required, it is likely that the actual demand curtailment will exceed the theoretical optimum (i.e. the absolute minimum required).

52. This becomes important when final spot prices are calculated for settlement purposes. Because final prices are based on actual *metered* demand, they will tend to reflect system conditions that are less constrained than when demand curtailment

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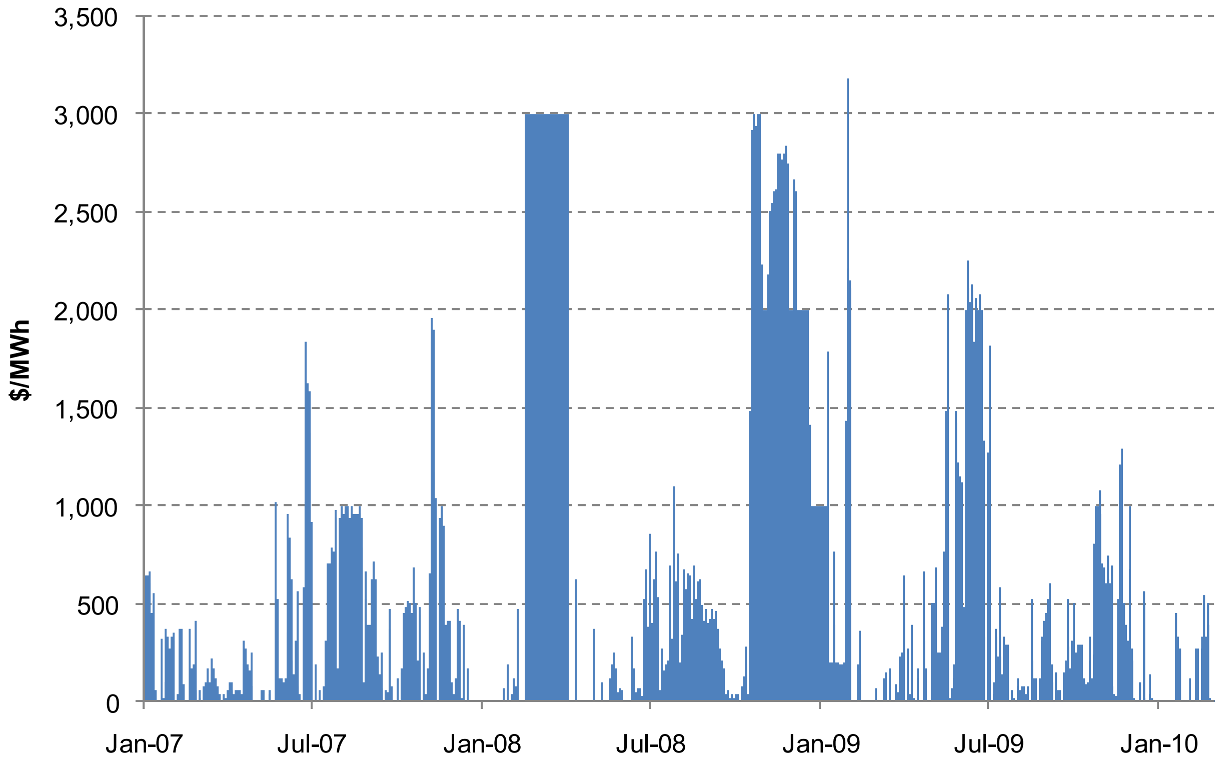
6 A completely unchecked supply shortfall will lead to a sustained reduction in frequency, with generation plant tripping out of service, exacerbating the shortfall. If unchecked, this will ultimately lead to cascade failure of the electricity system.

7 If insufficient demand is shed in a controlled manner, this can trigger Automatic Under Frequency Load Shedding (AUFLS), which is likely to be widespread and costly.

instructions were issued. Furthermore, because the final part of the supply schedule is typically quite steep, relatively small differences between forecast and metered demand can lead to sizeable shifts in final prices. This is illustrated by Figure 2 which shows the difference between the highest North Island generator offer price and the offer price for the generation tranche that is 50MW (around 1% of demand) below the highest offer[8].

Figure 2: Difference between highest offer price and offer price 50MW from top of supply schedule



53. Lastly, as noted above, spot prices are calculated based on the offer price for the generation tranche required to meet the last increment of metered demand. The cost of non-supply perceived by consumers is not directly reflected in spot prices[9]. Spot prices could be relatively low, or even settle *above* the cost of non-supply depending

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8 The chart shows the average of the differences across 48 trading periods each day. Data from 1 March 2010 appears to have been significantly affected by the change in the (administratively determined) Whirinaki capacity offer price from that date. Given that the Whirinaki offer price will become market determined once the plant is sold, the data after 1 March 2010 is unlikely to be representative and has been excluded.

9 Improving active demand side response, including more direct participation in spot price formation, is an important priority for the Electricity Authority and is being explored in other parts of the work programme. However, physical factors and transaction costs mean that uptake is likely to increase gradually over time rather than being widespread at the outset.

on generator offers[10]. This is in contrast to most products (e.g. oil, fresh fruit) where the value which different consumers would be prepared to pay will have a direct influence on its market price because consumers that value the product below the market price reduce their consumption, and vice versa. This also helps to achieve efficient rationing by ensuring that products that are scarce are allocated to those consumers who place the highest value on continued consumption.

54. Returning to the electricity system, in principle generators could set their offers at times of shortage to levels consistent with the value of non-supply to customers. It could therefore be argued that there is no need for administered scarcity pricing arrangements.

55. However, in practice generators may be unwilling to submit offer prices at these levels due to the risk that doing so will prompt regulatory intervention. The scope of any intervention is uncertain, given the potential for differing views on the boundary between acceptable and unacceptable offer prices. This regulatory uncertainty may in turn undermine the incentive for parties to provide last resort resources, such as voluntary demand-response and peaking generation.

56. In short, for the reasons noted above, spot price outcomes during emergency load shedding are likely to be suppressed.

4.1.2 Reduced IR cover – capacity scarcity

57. Even if generation capacity was always sufficient to meet intended demand, this would not by itself ensure adequate security. There is also a need for resources to be available at a few seconds notice to cover for the sudden loss of any large elements in the supply system. These back-up resources are referred to as instantaneous reserves (IR) and can take the form of additional generation (spinning reserve) or demand that can be shed very quickly (interruptible load).

58. To maintain normal security levels, sufficient IR is procured to cover the failure of the largest supply element in each island. In some circumstances the IR requirement may be partially relaxed to transfer resources from the IR market to the energy market, to meet energy demand. Partial relaxation of IR cover in real time dispatch means that the system cannot ride through all normal contingencies, and it increases the risk of widespread automatic load shedding being required. Any reduction in IR cover therefore compromises security to some extent.

59. As with spot prices for energy, the market clearing engine calculates spot prices for IR products[11] based on the offer prices for different tranches of reserve. The market clearing engine also co-optimises across energy and IR markets to identify the least cost mix of resources to meet demand.

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[10] In some situations prices can also settle well above the highest offer due to the way the mathematical model used to achieve least-cost dispatch finds solutions in some situations, particularly those which are close to, or actually, ‘infeasible’ (i.e. demand exceeding supply). See Appendix B for further explanation and an example.

[11] Four products – fast and sustained instantaneous reserve (known as ‘FIR’ and ‘SIR’, respectively) for each of the South and North Islands.

60. In the past, there was significant scope for price suppression during IR shortfalls because the relaxation of normal reserve requirements was not taken into account when calculating final prices. This altered in July 2010 when changes were made to arrangements for IR shortfalls. From that date, the System Operator was required to dispatch any available IR during a shortfall event[12]. Furthermore, the full level of IR cover is included for the purpose of calculating final prices[13].

61. This largely eliminated the artificial suppression of prices during IR shortfalls because the suspension of normal security requirements was no longer ignored. While some limited scope for suppression remains for the reasons set out in Appendix B[14], this is much less of a concern than in the past.

62. Although the changes introduced in mid-2010 largely addressed concerns about price suppression in IR shortfalls, they also increased the potential for very high prices to emerge if the system was very close to the point of infeasibility when calculating final prices[15]. For example, a case study based on system conditions and offers for 5 October 2009 indicated that prices could have settled above $40,000/MWh if demand had been higher, and current pricing processes were applied[16]. This price would have been more than forty times the value of the highest generator offer in the supply stack ($1,000/MWh).

63. While such a price outcome might be regarded as mathematically 'correct', it isn't clear they reflect the economic cost of supply as the result can be extremely sensitive to any changes in input parameters such as metered demand. Furthermore, there are inherent uncertainties in some of these parameters (e.g. due to meter precision).

[12] This refers to situations where there is insufficient offered IR and generation to maintain normal security *prior* to a contingent event (e.g. a plant failure). A shortfall can also occur *following* a contingent event, as reserves will have been activated to respond to the event. The issue of whether the System Operator is required to dispatch any further available IR immediately *following* a contingent event is subject to dispute, and is at the centre of a recent alleged Code breach. The Authority will monitor the investigation of this dispute, and determine whether it has any implications for the design of scarcity pricing arrangements for IR shortfalls. For more information see www.ea.govt.nz/act-code-regs/compliance/investigations-settlements-decisions/in-progress.

[13] In this context, spot prices refer to energy or reserve prices, given the potential for substitution at the margin.

[14] In essence, this arises because decisions about whether to reduce IR cover must be made in real time based on imperfect information, especially about expected system demand. Final prices are calculated based on actual demand data. It is therefore possible for an IR shortfall to occur in real time (compromising actual security), but not be evident when final prices are calculated because of differences between expected and actual conditions. That said, the residual scope for price suppression in IR shortfalls is now much less of a concern.

[15] An infeasible outcome refers to a situation which is technically impossible, e.g. having demand that exceeds supply. In the event of an infeasible outcome within the market clearing engine (MCE), a resolution process is invoked where conditions are progressively relaxed until a feasible outcome is reached. As set out in Appendix B, when the MCE produces a result that is just at the point of feasibility, extreme price outcomes can emerge as the MCE attempts to gain the very last increment of supply and deliver a feasible solution. An outcome that is only just feasible can occur purely by chance, or because the final pricing solution is infeasible when the MCE is run with full IR requirement. In that situation, the process of resolving the infeasibility can result in prices which are many multiples of the highest supply offer.

[16] See Appendix B for more detail.

This extreme sensitivity coupled with uncertainty over some input parameters can create doubt over the economic integrity of such price outcomes.

64. The potential for this type of issue to arise was recognised at the time changes were made to IR arrangements in mid-2010. However, given the urgent desire to address the potential for price suppression under (then) existing arrangements, the Electricity Commission judged it preferable to proceed with the changes which took effect on 1 July 2010, and address any subsequent issues in the context of scarcity pricing changes. Hence, some 'fine-tuning' amendments to pricing in IR shortfalls are proposed in this paper.

4.1.3 Rolling outages - energy/fuel shortage

65. The preceding sections focused on situations where demand or IR cover is reduced due to capacity shortfalls in real time. Forced load shedding may also be initiated to address a *projected* fuel or energy shortage that is weeks or months away (most likely due to a severe drought or thermal fuel or generation shortage). This form of curtailment is referred to as rolling outage load shedding.

66. In this situation, there would typically be more than adequate supply to meet near term demand, but consumers would nonetheless be forcibly curtailed to conserve fuel/energy for later use (i.e. to avoid more costly shedding at a later time). Once again, spot prices will be calculated based on metered demand, with no explicit account taken of the demand that has been forcibly curtailed.

67. A further factor to consider in this situation is the potential incentive on generators (whose supply offers will determine spot prices) to suppress spot prices. Generators can be net buyers in the wholesale market if they have large retail and/or contract commitments. Such generators could have an *incentive* to reduce spot prices in the near term if they do not believe they will face the full cost of any subsequent actual shortage[17]. Furthermore, large generators may also have the *means* to achieve this, because they have additional capacity that is not being utilised in the current period[18]. This creates potential for price suppression during periods of forced demand curtailment.

[17] Increasing output in the current period will raise a generator's net exposure to spot prices in later periods. Provided the generator expects to face the true cost associated with any subsequent actual shortage, its decisions should be economically efficient. However, a generator may not expect to face the full cost of any subsequent shortage because:

- as noted earlier, spot prices in *emergency* load shedding tend to be suppressed under *current* arrangements;
- if the generator is also a retailer, rolling outages will reduce its purchase obligations in the spot market. Such shortage costs would be met by consumers (less any credit due under their contracts or from the Compulsory Compensation Scheme).

[18] See previous footnote.

4.1.4 Public conservation campaigns - energy/fuel scarcity

68. A *projected* fuel or energy shortage may trigger a public conservation campaign, where consumers are requested by the System Operator to make voluntary power savings. End-users typically respond to these campaigns by reducing their demand.

69. Spot prices will be calculated based on highest generator offers and metered load, with no explicit account taken of the demand that has been shed. As with rolling outages, large generators could have the incentive and means to suppress prices in these situations, if they are net buyers in the spot market and they do not believe they will face the full cost of any subsequent actual shortage[19].

70. In principle, this concern is reduced by the fact that power savings in response to a conservation campaign would be voluntary. If spot prices were unduly suppressed by generator behaviour, consumers could curtail their savings effort. Demand would return to normal levels and the price suppression would be 'corrected'.

71. However, this assumes all end-users' decisions will be influenced by, and therefore reflected in, spot prices. Arguably, public conservation campaigns operate by asking end-users to suspend their individual interests, and to act for the good of the country. This creates a potential for inconsistencies to arise between the value that end-users ascribe to security and spot prices[20]. For example, end-users might continue to conserve power during a campaign, even if the price signal from the spot market and/or in their retail contract was below the value of foregone consumption.

72. Another point to consider is the effect of conservation campaigns (and associated lobbying) on public confidence. Net buyers[21] in the spot market have a financial incentive to 'talk up' the risk of a supply shortage in advance of a campaign, to persuade the media, consumers and policy makers of the need for this measure.

73. The Authority has recently determined that the trigger point for starting a public conservation campaign will be hydro storage falling below the 10%[22] risk curve and that a campaign will cease when storage has returned above the 8% risk curve. These trigger points were not defined in the past, and their adoption should reduce the scope for lobbying. However, the Authority retains a discretion to alter these

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19 Once again, increasing output in the current period increases the generator's net purchase exposure in later periods.

20 Implicit in the preceding discussion is an assumption that end-users will receive price signals from their retailers that (broadly) reflect the conditions in the wholesale market. This can occur through end-user/retailer contract structures and/or mechanisms such as 'paid for' demand savings schemes. To the extent that technology or other barriers impede this, there is an increased potential for a discontinuity to arise between end-user decisions and spot prices.

21 These can be generators with net sales commitments which may be difficult to meet from their generation capacity, or wholesale buyers (large industrial users or retailers) exposed to high spot prices because they have insufficient hedge to fully cover their intended demand.

22 This is the point where the system is judged to face a 10% risk of shortage in the absence of further measures. See www.ea.govt.nz/consumer/customer-compensation-scheme/ for more detail.

trigger points, and so the incentive on some participants to talk up the level of supply risk has not been entirely eliminated.

74. The lobbying and the frequent use of campaigns in recent years[23] appears to have fostered a perception that New Zealand is unduly vulnerable to supply crises. This acts to undermine business confidence in New Zealand, and increases the likelihood of ad-hoc policy change.

75. Even a very modest change in the economy's growth path due to confidence effects could significantly raise the effective cost of public conservation campaigns. For example, if gross domestic product was reduced by $5 million on average (approximately 1/400th of one per cent of GDP) through adverse confidence effects, this would raise the effective cost of public conservation campaigns by approximately $200/MWh[24].

76. The recently introduced Customer Compensation Scheme should encourage retailers to more actively use commercial arrangements to manage dry year risks, rather than rely on 'free savings' from consumers. However, the scheme does not alter the potential incentive for some other wholesale participants (such as large industrial users that are not fully hedged) to lobby for such campaigns.

Q1. To what extent is price suppression an issue with current pricing arrangements?

4.2 Why does spot price suppression matter?

77. It is important that spot prices during supply emergencies provide efficient price signals. Otherwise, the incentive for efficient investment will be undermined and there will be increased risk of forced rationing. This outcome would be detrimental to the long term interests of consumers. The reasons for this are explained further below.

4.2.1 Effects of price suppression

78. If spot prices are generally suppressed by non-price interventions during supply emergencies, this will lead to a so-called 'missing money problem'[25] with inadequate provision of last resort generation and/or voluntary demand side response. The missing money problem arises because last resort resources, by their nature, are only

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23 Campaigns were required in 2001, 2003 and 2008, and planned in 2006.

24 This assumes that campaigns reduce load by approximately 160 GWh (40GWh per week over a 4 week period), and that the frequency of use doubles to once every ten years on average in the absence of corrective policy measures.

25 This issue has been discussed extensively in the international literature. For example, see "On an 'Energy Only' Electricity Market Design for Resource Adequacy", September 2005, *Professor William W. Hogan*, Harvard University.

required to operate for a few hours a year, or on a very infrequent basis[26]. To cover the standing costs (i.e. capital costs and fixed operating & maintenance costs) of last resort resources, spot prices need to be at very high levels during the brief or infrequent periods when they are operating if they are funded solely from spot market revenue.

79. Unless providers can reliably expect adequate revenue from spot sales (or equivalent hedge contract payments), there will be insufficient incentive to provide the optimum level of last resort resources. This in turn will lead to security being below the optimum level, with increased reliance on involuntary load shedding or other measures with higher costs for society.

80. In an operational context, the missing money problem will manifest itself in the form of reduced availability/commitment of demand response capacity or slow start generation plant, or poor fuel management decisions. In a longer term context, it can lead to reduced incentives to retain or invest in infrequently-used power stations, fuel stocks, and/or demand response capability.

81. An additional outcome of price suppression is that non-economic demand-rationing will occur more often. Parties who might be prepared to reduce demand in response to spot price signals will have reduced opportunities to enter into such arrangements. Conversely, there will need to be greater reliance on non-price mechanisms to ration available supply, meaning that parties with relatively higher consumption values are more likely to be forcibly curtailed.

82. Furthermore, to the extent that there is a significant quantity of load whose value of consumption is materially lower than the average value over all customers[27], a suppressed price signal could result in peak demand growth rates being greater than would be economically efficient given the cost of building supply-side assets (generation and network) to meet such peak demand.

83. Finally, it is important to recognise the potential flow on impacts of compromised security. In addition to the immediate consumer impact of forced load shedding or conservation campaigns, there may be longer term costs due to reduced investor confidence in New Zealand as a place to do business. Compromised security also raises the likelihood of an ad-hoc policy intervention, during or immediately after a supply emergency. As noted by the Authority[28]:

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26 For example, resource needed to cover extreme 'dry year' risk might only be needed for 6-8 weeks every 60+ years.

27 Various New Zealand and international surveys on the value of lost load have indicated that there is a significant range of electricity consumption values both between and also within customer classes. For example, a water pumping station might be able to forego electricity at times of peak demand at relatively low cost, whereas a company manufacturing high-tech products may incur much higher costs. Similarly, some consumers may be able to reduce some proportion of their consumption at relatively low cost, but would incur much greater costs if all their consumption were curtailed.

28 See "Interpretation of the Authority's statutory objective", *Electricity Authority,* 14 February 2011.

> "*.. security and reliability arrangements need to be durable in the face of high impact, low probability events or the impending prospect of those events occurring (hereafter, 'adverse events'). Adverse events can reduce efficiency by creating uncertainty for investors as a result of reactive changes to regulatory settings*.
>
> *...the Authority believes the potential costs of regulatory uncertainty and ad-hoc interventions should be taken into account in determining minimum total costs*."

Q2. To what extent do you agree that the spot price suppression will adversely affect security of supply?

4.3 Evidence to date

84. Evidence to date presents a mixed picture on the extent of a missing money problem. Assessments undertaken by the Electricity Commission up until 2009 and subsequently by the System Operator indicate that the system would have sufficient generation resources to meet the standards for capacity and energy adequacy[29].

85. However, as noted in those assessments, the projections were based on assumptions about plant retention and planned investments. The results also rest on assumptions about the way that market participants would be expected to operate[30] existing plant during tight system conditions. Some of these assumptions are open to debate.

86. Key areas of concern include:

- there was an increasing frequency of very tight capacity situations (including IR shortfalls) in the North Island – particularly during 2009. This has highlighted a concern about the adequacy of unit commitment[31] incentives, and the incentives to invest in peaking resources (either demand response or fast response flexible generation). Examination of historical spot prices tends to reinforce this concern, given the considerable gap between revenues that would have been realised by peaking generation and its expected cost;

[29] In simple terms, 'capacity adequacy' refers to having sufficient MW capacity available to meet periods of peak demand, whereas energy adequacy refers to having sufficient GWh of energy resource to meet periods of fuel shortage (typically reduced hydro inflows during a dry-year event).

[30] In terms of fuel management decisions in an energy security context, and unit commitment decisions in a capacity context.

[31] Unit commitment refers to the decisions generators need to make as to whether they should 'commit' to starting up a generator in order to offer its output into the market. The challenge is that some thermal generators incur significant fuel start-up costs, and can take a long time to start-up (12-24 hours), yet have no certainty as to the prices they may be able to earn for such generation once they have started up. Some hydro generators face similar challenges with respect to hydro storage in terms of having to make reservoir release decisions many hours ahead of when the water would be required to generate.

- when hydro conditions deteriorate, thermal generation is expected to ramp up to reduce pressure on hydro storage. While this general pattern has been evident in dry periods, during the 2008 drought there were periods when thermal generation wasn't running at full capacity and discretionary hydro storage was still being drawn down. This occurred even though the assessed likelihood of subsequent shortage was significantly greater than 1 in 60, which is the security standard sought by the government;
- 'last resort' generation plant appears to face some uncertainty. On one hand, Contact Energy is currently commissioning a new 200MW peaker station in Taranaki, and Todd Energy and TrustPower are proceeding with plans to build new peaker plants. On the other hand, Genesis has made a number of statements regarding the potential for reducing generation capability at Huntly[32]; and
- discretionary demand reductions are a valuable source of flexibility to address dry year risk. However, aside from demand cuts by industrial and commercial users exposed to spot prices, there has been little evidence of active demand response initiatives. Indeed, for residential and commercial customers, the provision of incentive-based arrangements appears to have lessened over time. For example, in 2001 Mercury offered rebates[33] to residential customers who saved power. No similar arrangements to mass market customers were offered in 2008. Instead, there appears to have been increasing reliance on generalised public conservation campaigns, with this instrument used in 2001, 2003 and 2008 (and prepared for use in 2006);

87. While the historical data presents a mixed picture, the fact remains that the wholesale market is reliant on spot prices to provide the signals for effective operational and investment decisions. Unless these signals properly reflect the value of electricity during supply emergencies, it is difficult to have confidence that security levels will be maintained at appropriate levels. Furthermore, while any deterioration in *investment* margins might take 12 months or longer to emerge, a change could occur more swiftly if manifested through poor *operational* decisions by market participants.

88. It would be possible to adopt a 'wait and see' approach, and delay decisions pending firm evidence of problems. However, given the high cost of supply shortfalls, this approach would carry a risk of severe adverse outcomes: both in terms of the shortage incident(s), and pressure for ad-hoc intervention[34]. For this reason, a pro-active approach is proposed to give greater assurance about security outcomes.

Q3. What is your assessment of historic security of supply performance, and the likely future performance under current arrangements?

32 For example see Genesis Statement of Corporate Intent: 2010/11-2013, and evidence presented to the Commerce Select Committee of Parliament in March 2011

33 Some other retailers offered community based incentive schemes.

34 As set out further in section 6.2.2, the Authority has identified that having market arrangements which are durable (i.e. not subject to ad-hoc intervention) is a key requirement to meet the reliability limb of its statutory objectives.

5 Scarcity pricing: proposed elements

Section summary

- Core elements of proposed scarcity pricing arrangements are:
  - Emergency load shedding – a price floor would apply
  - IR shortfalls - a modified process would apply to reduce the scope for suppression or unduly high prices (many multiples of the highest supply offer) when the final pricing run is close to infeasibility[35]
  - Rolling outage load shedding – a price floor would apply
  - Public conservation campaigns – one or both of the following:
    - a price floor would apply
    - net spot market exposures would be disclosed in a form that indicates which parties are expected to benefit financially from public conservation campaigns.
  - A transition would apply which::
    - stages the introduction of measures over time (starting with the floor for emergency load shedding, IR price changes and disclosure of net spot market exposure)
    - introduces all final measures from an initial date, but with a phased increase in the values for respective price floors – the timetable for phased increases could be pre-defined or be subject to ongoing assessment by the Authority and/or
    - adopts the whole package (including disclosure) with full scarcity price values, but moderates the impact of price floors with a transitional 'stop-loss' type mechanism that is progressively relaxed over time
  - Key elements of the scarcity pricing regime would be reviewed every three years, with a 12 month lead time before any material changes to the scarcity pricing regime come into effect[36].

89. Ideally, the concerns about price suppression noted earlier would be addressed by ensuring that electricity users could directly participate in spot price determination – as typically occurs in markets for other products. The resulting market price should better reflect users' preferences about the value of continued supply, and eliminate the risk of price suppression (or overshooting). It should also ensure that available supply is allocated to those parties who place the highest value on continued usage.

90. Although the Authority is pursuing initiatives to improve the scope for demand side participation in the wholesale electricity market[37], it is important to acknowledge that

[35] In essence, infeasibility refers to a situation where the market software is at the limit of its ability to clear the market. At this point, the results can become extremely sensitive to small variations in input parameters, such as the level of metered demand.

[36] The 12 month lead time would not apply if the change is required to address an urgent issue.

there are significant technological and transaction cost barriers in this area. In particular, if mandatory load shedding is required in an emergency, it is not practical to selectively disconnect most users according to their individual security/price preferences. While the level of demand-side participation is likely to grow over time, the inability of most users to directly signal their preferences in supply emergencies is expected to remain for some time. This means that the potential for price suppression will continue.

91. The initiatives being proposed by the Authority under the banner of 'scarcity pricing' are intended to address this concern. In broad terms, they would alter the way that spot prices are determined in a supply emergency to reduce the risk of spot price suppression and/or improve regulatory certainty.

92. As noted above, supply emergencies (and associated interventions such as forced load shedding) can take different forms. The proposals take account of these differences. The particular changes to pricing arrangements for each type of supply emergency are set out in the following sections.

93. An alternative approach has also been considered. This is discussed in section 6.3 which looks at reasonably practicable options.

5.1 Capacity shortage - emergency load shedding

94. In a short term capacity shortage, the System Operator may invoke the so-called "grid emergency" provisions of the Code[38] to request purchasers or distributors to reduce demand, or require the disconnection of demand[39]. For the reasons noted in Section 4.1.1, final prices are unlikely to reflect the costs associated with forced demand curtailment.

95. To address this issue, it is proposed that load shedding instructed under Part 8, section 6(1)(d) of the Code, will trigger application of a scarcity price floor in final pricing. This value would apply as a price floor in the region of the grid affected by the capacity shortage. For the reasons set out in section 6.5, it is proposed that scarcity pricing would only be invoked if a capacity shortage was widespread, and was affecting one or both islands.

96. The proposed price floor for emergency load shedding is $10,000/MWh. The derivation of this value is discussed in Appendix E. It is proposed that this value will be reviewed periodically to ensure that it is appropriate.

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37 For example the proposals to allow qualifying demand sources to be dispatched in a manner similar to generation, and the proposed changes to demand side bidding and forecasting arrangements.

38 A grid emergency is defined in Part 1 of the Code. In broad terms, it covers situations where the System Operator considers that there is insufficient capacity being offered to meet forecast demand and normal security requirements, and/or there is a risk to public safety. Not all grid emergencies result in forced load shedding. Grid emergencies would only trigger scarcity pricing if forced load shedding was invoked.

39 See Technical Code B of Part 8 of the Code for a full list of the actions that the System Operator can take.

97. From an operational perspective, it is envisaged that final prices would first be calculated using existing procedures. If the level of final prices for the island(s) affected by shortage is already $10,000/MWh (or higher), no scarcity pricing adjustment would apply. However, if final prices were below this level, an adjustment would be applied to bring them to $10,000/MWh.

98. The exact implementation details for this approach have not been determined at this stage. For example, decisions would be required on:

- the exact test for determining whether prices (before adjustment) have reached the floor level, given that New Zealand utilises a nodal pricing regime. It is likely that a weighted average measure of nodal prices will be required to assess prices in the island or islands affected by shortage;
- the means of calculating any adjustments to final prices (if required). In particular, consideration will be required about the treatment of nodal price effects within any island affected by shortage; and
- the extent to which scarcity pricing arrangements are reflected in pre-dispatch, real time, and final pricing arrangements (noting the desirability of providing signals ahead of time to the maximum extent feasible).

99. While decisions on the exact form of implementation have not been made at this stage, sufficient analysis has been undertaken to provide a high degree of confidence that there are workable options.

Q4. What is your view of the proposed price floor to be applied in emergency load curtailment?

5.2 Forced demand curtailment in AUFLS event

100. As set out in section 5.1, forced demand curtailment in grid emergencies or rolling outages would be instructed by the System Operator. However, curtailment can also occur without any instruction from the System Operator due to the sudden loss of a supply side asset and the consequent immediate triggering of automatic under frequency load shedding relays (AUFLS)[40].

101. If an AUFLS event was to occur, electricity users will experience curtailment without any prior notice. For that reason it could be argued that an AUFLS event should trigger scarcity pricing. However, there is one complication that arises with AUFLS that does not feature with the other forms of forced load shedding.

102. Because AUFLS can only trigger discrete pre-defined demand curtailment blocks (i.e. currently set at 16% or 32% of each island's total load), there is a high likelihood that

[40] For more information on AUFLS, see System Operator Report: Automatic Under-Frequency Load Shedding (AUFLS) Technical Report, *Transpower,* August 2010.

AUFLS will cut more load than is strictly required to address a security event[41]. This means that some operating generation would also be required to reduce output to achieve system balance in an AUFLS event.

103. If a scarcity price were applied at that point, generators (and schedulable demand response) would be precluded from reacting to this price signal. For this reason, it is arguable that a scarcity price signal for an AUFLS curtailment is not appropriate. Experience in the Australian market during the Victorian bushfires in 2007 bears out this concern. In the light of that experience, the Australian market rules were changed to exclude AUFLS as a trigger for scarcity pricing, and to limit its application to instructed load shedding.

104. It is proposed that the same stance be taken in New Zealand. An AUFLS event would therefore not trigger scarcity pricing.

Q5. What is your view of the proposed treatment of load curtailment in AUFLS events?

5.3 Capacity shortage - shortfall in instantaneous reserves

105. As set out in Section 4.1.2, changes introduced in mid-2010 by the Electricity Commission largely addressed the potential for artificial price suppression to arise during IR shortfalls. However, the changes did not address all concerns. In particular:

(a) some potential remains for spot price suppression to arise (albeit with much less scope than for forced load shedding); and

(b) potential exists for spot prices to settle at levels which are many multiples of the highest offer price if the final pricing solution is close to the point of infeasibility in the market clearing engine. While the outcome may be mathematically correct, uncertainties around some input parameters (e.g. due to meter error factors) mean the resulting prices may have doubtful economic integrity.

106. In light of these factors it is proposed that an additional procedure would be applied when IR shortfalls occur in dispatch. This procedure would introduce a virtual IR

[41] Strictly speaking, the same observation applies to emergency load shedding. However, the extent of any additional shedding is likely to be much smaller (because it results from forecasting uncertainties) and it is unlikely that significant generation capacity will be forced to back off.

provider[42] with an offer price that is the greater of the highest dispatched IR or energy offer, or an IR scarcity price from a pre-defined IR shortage function[43].

107. More specifically, the following approach is proposed:

- Step 1: Is there an IR shortage in any real time dispatch interval of a trading period. If Yes then go to Step 2, else Exit and publish prices in the normal way;
- Step 2: Solve final pricing as per current processes. Among other things, this will identify whether any infeasibilities arise; If no infeasibility arises, go to Step 4;
- Step 3: If any IR infeasibility arises in final pricing, then resolve the IR infeasibility using the existing processes (this is expected to produce an outcome that is 'just' feasible) and then go to Step 4;
- Step 4: Add the virtual IR provider to the system. The offer price for the virtual resource is the greater of the highest dispatched IR or energy offer, or the IR scarcity value from the pre-defined IR shortage function;
- Step 5: Solve final prices allowing the virtual IR provider to be scheduled if necessary; and
- Step 6: Publish results.

108. The precise profile of the IR shortage function has not been formally established at this point. However, it is expected to be a relatively simple linear stepped function, with the values rising according to the size of the IR shortfall, and with steps approximating the price curve marked as 'scarcity pricing' shown in Figure 29.

109. Under this arrangement, final prices during IR shortfalls would continue to be determined solely from market offers in most circumstances[44]. Furthermore, under

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42 This could be in the form of a virtual provider of interruptible load or an adjustment to IR requirements. The detail of the proposed change will be analysed in the next phase of work.

43 This shortage function will define an IR scarcity price for differing levels of IR shortfall. These would be defined in steps, with the highest step at no more than the scarcity price for emergency load shedding ($10,000/MWh).

An alternative approach has also been considered where a further solve is run if existing processes produce final prices that are many multiples of the highest offer. In this situation, a pre-defined 'relaxation' buffer would be applied in the further price solve to move the system slightly away from the point of infeasibility. This approach has similarities to the current high spring-washer price resolution process. While there is some merit in addressing both situations in an analogous manner, the 'relaxation' approach would still leave uncertainty around prices in IR shortfalls. It is possible that spot prices could still be many multiples of the highest offer. Depending on the trigger, it is also possible that the 'relaxation' approach could replace 'valid' price outcomes.

44 It is important to note that even with the modified process, final prices could clear at a level that is more than twice the level of the highest offer (if the same provider is the marginal resource for both fast instantaneous reserve and sustained instantaneous reserve). Furthermore, final prices will reflect the effect of marginal transmission losses.

this proposal, the System Operator would continue to procure all available energy and IR resources in real time prior to any contingent event[45].

110. In summary:

(a) any adjustment to final pricing would be limited to situations where the system has experienced an IR shortage in real time, and the 'normal' final pricing run (with full IR cover) was close to infeasibility. This should mean that market based processes would continue to apply for most IR shortfalls;

(b) this would reduce the potential for price suppression, and for prices that are many multiples of the highest offer to emerge, due to way that the MCE treats situations that are close to mathematical infeasibility; and

(c) all available energy and IR resource would continue to be procured in real time.

111. Given these features, it is proposed that the IR pricing approach along the lines described above would be adopted as part of scarcity pricing arrangements, subject to addressing any implementation issues[46].

Q6. What is your view of the proposed approach to pricing during IR shortfalls?

5.4 Energy/fuel shortage - rolling outage load shedding

112. In a situation where emergency load shedding is otherwise expected in the future, the System Operator may invoke the rolling outage provisions in Part 9 of the Code[47]. These provide for the System Operator (after consultation with the Authority) to make a supply shortage declaration, and then to direct specified participants to reduce their electricity demand in accordance with pre-specified plans[48]. These demand reduction instructions would provide for targeted cuts to be implemented with prior notice (unlike emergency load shedding).

113. Under existing arrangements, the final price will be determined by the highest generator offer required to meet metered demand (i.e. excluding demand that was forcibly curtailed). Furthermore, a generator may have an incentive to suppress near term prices because it does not face the full cost of any subsequent shortage for the reasons set out in paragraph 67. This creates potential for price suppression.

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45 Up to $100,000 per MW (which is the value of the constraint violation penalty in the MCE).

46 Some analysis of implementation issues has been carried out, and this has not identified any fundamental roadblocks. However, further detailed work will be required before a final determination can be made.

47 A emergency is defined in Part 1 of the Code. In broad terms, it covers situations where the System Operator considers that there is insufficient capacity being offered to meet forecast demand and normal security requirements, and/ or there is a risk to public safety.

48 See Section 9.15 of Part 9 of the Code for more detail.

114. Introducing a scarcity price floor for *emergency* load shedding (as discussed in section 5.1) should reduce the incentive for a generator that is short of supply to run down its hydro storage or thermal stockpiles to suppress near term spot prices. However, to be fully effective, participants would need to perceive the prospect of *sustained* emergency load shedding (with prices of at least $10,000/MWh for weeks or longer) as credible. Some parties are likely to question this assumption[49].

115. To address this, a distinct price floor could be applied in the final pricing process[50] if rolling outage load shedding is instructed under section 9.15 of Part 9 of the Code.

116. Based on the analysis set out in Appendix E, a $3,000/MWh price floor is proposed for rolling outages. This is significantly below the proposed scarcity price floor for emergency load shedding ($10,000/MWh) and the value of lost load used for transmission investment purposes ($23,185/MWh). This reflects the lower expected societal cost of rolling outages, as compared to sudden and unexpected load shedding.

117. However, it is important to recognise that if rolling outages are applied, they could persist for weeks or longer, because energy/fuel shortages are extended events by their nature. A sustained period of spot prices at $3,000/MWh would create significant stress for market participants.

118. Net purchasers would need to be highly hedged and/or have reliable demand response capability to weather a period of very high spot prices. An indication of the required hedge level can be obtained by considering a notional retailer's exposure at differing hedge levels. Figure 3 shows the net cost that a retailer would face[51] if spot prices were at $3,000/MWh over a four week period. For ease of comparison, the costs are expressed in terms of dollars per customer account, assuming the retailer is servicing residential end users[52].

119. The financial impact varies substantially depending on the level of hedging. At hedge levels below 80%, the cost over a four week period would be $500/account or greater. For a stand-alone retailer with its customer base as the main asset, it appears

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49 As discussed later in the paper, the same issue arises for rolling outage load shedding, although the issue is arguably less severe because the associated price floor is lower than for emergency load shedding.

50 Again, this would be subject to the minimum geographic threshold discussed in section 5.6. Note also that a number of alternatives exist as to how the change would be reflected into the Market Clearing Engine. The precise choice would be determined once a preferred overall design has been firmed up.

The alternative of an *offer price floor* for discretionary generation was also considered, rather than a market price floor. The advantage of an offer price floor is that it could more directly address the concern that discretionary generation is used inappropriately. However, this approach is not favoured because it would be very difficult in practice to distinguish between discretionary and non-discretionary generation sources, especially for hydro generation.

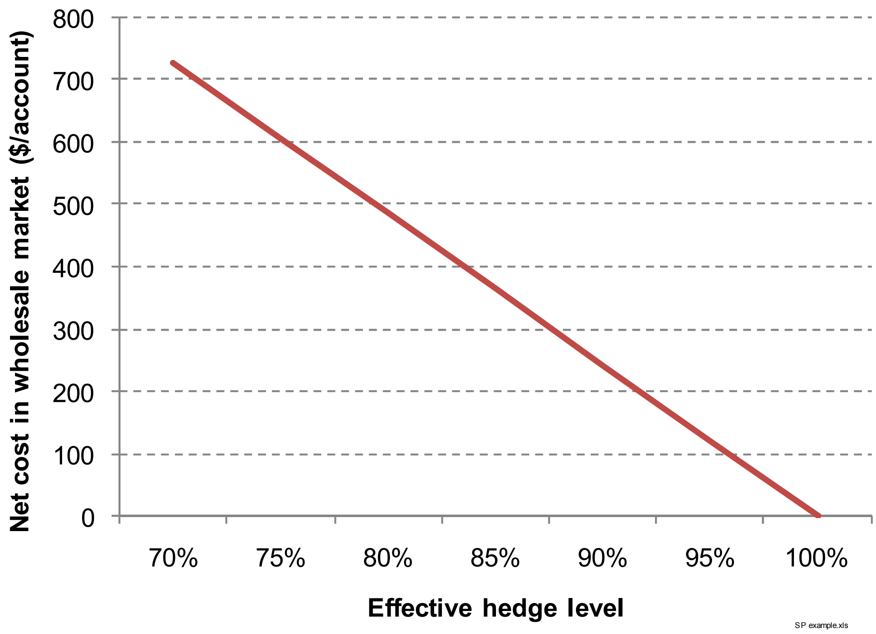
51 The cost of wholesale energy (at $3,000/MWh) for any unhedged purchase volume, less the wholesale contribution embedded in the retail tariff (assumed to be $75/MWh).

52 It assumes that each end-user consumes 208 kWh per week (based on around 8,000/kWh per year, with higher winter demand).

unlikely such costs could be sustained, as the costs incurred over the four week period become substantial relative to the expected lifetime value of an account[53].

120. However, the position is different for a stand-alone retailer that is more highly hedged. Figure 3 indicates that provided such a retailer is hedged at 90% or higher, its loss on any unhedged purchase volumes from a four week period at $3,000/MWh would not exceed the approximate long term value of the customer base[54].

Figure 3: Estimated financial impact for stand-alone retailer (4 weeks at $3,000/MWh)



121. Another related issue is the impact of prudential requirements during a period of high spot prices. The clearing manager sets required prudential levels to cover the market's expected net exposure to a participant (purchases less generation) over a credit period of approximately 57 days. High spot prices can have a very significant impact on this expected net exposure. Participants can be required to provide large amounts of additional prudential security, often at the same time that they are required to settle the previous month's transactions. In addition, there are uncertainties in the process of estimating the market's net exposure, which can make it more difficult for participants to manage their prudential obligations. The Authority has commenced a review of settlement and prudential arrangements which may help to improve the quality of the net exposure estimate.

122. Under current prudential arrangements, there is a mechanism to allow purchasers to lodge qualifying hedge contracts as prudential security, provided such contracts are settled through the clearing manager. This means that other forms of security (cash, bonds, guarantees) are only required for any residual purchase exposure. In

[53] This is based on the values observed for sales of retail businesses in New Zealand and Australia, which have ranged between approximately $500-$1,000 per account.

[54] There is a separate issue relating to the timing of cashflows which is discussed later.

principle, this means that prudential requirements should be manageable for a highly hedged purchaser.

123. However, if a purchaser wants to lodge a hedge, this requires the counterparty's approval and may be a factor in negotiating the price. If a purchaser is hedged but does not have the counterparty's agreement for the hedge to be lodged, the purchaser could be required to provide large amounts of prudential security during periods of high average spot prices. The difference in timing between the requirement to satisfy a prudential call and the settlement of a bilateral hedge contract can cause substantial cash flow difficulties for a purchaser.

124. Settlement is currently on a *gross* basis. Wholesale purchasers and holders of lodged out-of-the-money hedges are required to pay the clearing manager in cleared funds by 2 pm on settlement day for their gross purchases and hedge costs. The clearing manager pays generators and holders of lodged in-the-money hedges for their gross generation and hedge income by 4.30pm on the same day. During a period of high spot prices, gross settlement requires purchasers to find substantial levels of cash for settlement purposes, even though the purchaser may be highly (or fully) hedged. It is conceivable that in a period of extremely high prices, some parties may find it difficult to access the required cash amounts, even though it may only be for a period of hours[55].

125. Gross settlement arrangements and the non-recognition of the prudential strength of un-lodged hedges (as well as spot price pass-through contracts) have already been identified as issues warranting consideration in the review of settlement and prudential arrangements. The Authority's objective is to have Code changes flowing from the review in effect by the 2012 winter.

126. In assessing the practicality of a floor price during rolling outages, another matter to consider is the sustainability of merit-based dispatch using generator offers if the system is under severe stress. In principle, rolling outages will shrink demand sufficiently to ensure that there is always a 'surplus' of supply in the current trading period, and a merit-based auction can be sustained.

127. However, during a period of extremely tight supply, constraints other than the overall energy balance can become important. These can include issues such as tighter restrictions on river flows imposed by resource consent requirements or voltage stability issues. The level of difficulty in managing these issues might increase to a point where it is preferable to temporarily move to an administered form of dispatch, rather than seeking to address them through offer prices and/or security constraints within the market clearing engine.

128. In combination, the commercial and physical issues that could arise in rolling outages mean that a price floor may not be viewed as being credible by some parties. On this view, 'hard wiring' a spot price floor during rolling outages will not have the desired

[55] For generators, there is also a risk of short payment if any purchaser defaults, as any the shortfall from any purchasers default is spread across all generator payments on a pro-rata basis under current arrangements. This could also create flow-on impacts.

positive effect on incentives, and could instead create additional risks. Regulatory predictability would be undermined as the Authority could come under pressure to deviate from the announced policy.

129. The alternative view is that the risk of very high prices during rolling outages is not new, because energy shortages are an inherent risk in New Zealand and the wholesale market has had uncapped prices since its inception in 1996. On this view, the introduction of a scarcity price floor in rolling outages would reduce the scope for uncertainty about an exposure that already exists.

130. The underlying issue in these opposing views is where to draw the boundary between the operation of the market (where resources are allocated according to price signals) and administered arrangements (where an alternative process applies).

131. At this point, the Authority believes that it is preferable to treat rolling outages as *generally* being inside the market boundary. This means that it would be important to ensure that spot prices cannot be unduly suppressed by forced load shedding. For this reason, the Authority inclines on balance toward including a spot price floor during rolling outages within the overall scarcity pricing design.

132. However, the Authority also recognises that situations could arise where rolling outages are invoked, but the underlying cause is outside the scope of a reasonable market boundary. For example, a devastating earthquake could cause widespread damage to electricity infrastructure, and necessitate rolling outages. In that situation, it is envisaged that a price floor would not be applied. This raises the broader issue of safeguards, and this is discussed further in Section 7.

Q7. What is your view of the proposed price floor to be applied in rolling outage load curtailment?

5.5 Energy/fuel shortage – public conservation campaigns

133. As noted in Section 4.1.4, public conservation campaigns reduce demand and lower spot prices. From a policy perspective, the central concern is that spot prices during such campaigns may not properly reflect the full cost being borne by society.

134. The sources of concern with current arrangements are:

(a) the potential incentive on some generators to run down discretionary hydro storage or thermal fuel stockpiles (which lower spot prices) in the near term because they do not expect to face the full cost associated with any subsequent actual shortage;

(b) the potential for spot prices to be artificially suppressed because some users reduce their electricity consumption out of a sense of public duty when official conservation campaigns are called[56]; and

(c) the potential for parties that can benefit from a public conservation campaign to 'talk up' security concerns. This pre-campaign lobbying and the actual use of campaigns may undermine future investment confidence and increase the risk of ad-hoc intervention.

135. In principle, item (a) could be addressed by the introduction of a floor price for *rolling outages* (discussed in section 5.4) because market participants should be prepared to pay higher spot prices prior to reaching the stage where rolling outages are required, to reduce the probability of paying the very high price floor if rolling outage load shedding is ultimately required. However, it relies on parties perceiving the threat of high spot prices during rolling outages as credible and sustainable. As noted earlier, there are some doubts in this area[57].

136. It might also be argued that applying scarcity pricing for rolling outages but not conservation campaigns could increase the incentive on participants to lobby for conservation campaigns. On this view, industry participants would have two sets of incentives to call for conservation campaigns: that is, to get earlier relief from high spot prices and to reduce the risk of rolling outages occurring, which would trigger scarcity prices[58].

137. Furthermore, items (b) and (c) in paragraph 134 would not be addressed by a rolling outage price floor. The latter concern will be reduced by the customer compensation scheme being introduced on 1 April 2011. That scheme is designed to address the incentive on retailers to call for conservation campaigns as a means of reducing their purchase *volume* in the wholesale market. However, the scheme as presently structured is not designed to address the financial incentive arising from a reduction in *spot prices* (see Appendix C for more detail).

138. In principle, the rate of compensation payable to consumers by retailers could be increased to seek to address both the *volume* and *price* effects associated with public conservation campaigns. However, the degree of price benefit will vary across retailers depending on their individual hedge position. Retailers that are highly hedged obtain little or no benefit from a spot price reduction[59], and lightly hedged

[56] In other words, some consumers may place a higher value on continued usage than the prevailing spot price, but reduce their usage nonetheless because of official requests for conservation. In this case, the spot price will not reflect the opportunity cost being incurred by those consumers.

[57] In addition, rolling outage load shedding may reduce net buyers' exposure to high spot prices by reducing their purchase quantities. This effect will not be addressed by a price floor or the customer compensation scheme being introduced from 1 April 2011.

[58] Assuming that applying a scarcity price floor for rolling outages results in higher expected spot prices in rolling outages than under current arrangements.

[59] Furthermore, a retailer that has hedges exceeding its purchase requirements will be adversely affected by a fall in spot prices. The variability in outcomes due to differing hedge positions only applies to the price effect associated with public conservation campaigns. The volume effect is not affected by a retailer's hedge position.

retailers could gain a significant benefit. For this reason, it would be difficult to address the price-based incentives to call for public conservation campaigns by adjusting the rate of payment in the customer compensation scheme.

139. Furthermore, the compensation scheme only applies to retailers. Other parties can have strong incentives to call for and rely on public conservation campaigns to reduce their costs. This can include major industrial users with unhedged load or generators with contracts that exceed their production capability. These factors mean that there could be a continuing financial incentive for some parties to lobby for, and to over use, public conservation campaigns.

140. To address these remaining concerns, two broad sub-options have been considered – a disclosure mechanism to expose parties' interest in lobbying for campaigns, and a financial mechanism to reduce the incentive to lobby for campaigns.

5.5.1 Disclosure mechanism

141. Parties that lobby for public conservation campaigns typically advance their case based on the national interest, and do not refer to the private benefits they could obtain from a campaign. If such parties' financial motives were made more transparent, this could deter lobbying and 'talking up' of security concerns that typically precede campaigns. The disclosure mechanism would also provide the Authority with information it needs to 'stress test' market arrangements and assess the durability of reliability arrangements.

142. In principle, the increased disclosure requirement could be applied only to parties calling for a campaign. However, there are some practical difficulties with this approach:

- the trigger for requiring disclosure would be hard to pin down because 'lobbying' can take many different forms, from broad media campaigns through to private approaches to Ministers. It would be hard to define the threshold in a way that achieves the intended purpose;
- the call for a campaign may come from an organisation or spokesperson, some of whose members or associates are exposed to high spot prices. Applying the disclosure obligation on the umbrella organisation or spokesperson would serve no useful purpose (since they are unlikely to have any direct exposure to spot prices). In theory, the disclosure obligation could be applied to individual members or associates of the umbrella body or spokesperson. However, this assumes they can be identified, and this may not be feasible. There is also a question about whether umbrella organisations or industry spokespersons would fall within the jurisdiction of the Code;
- if the obligation to disclose was triggered after lobbying began, there would necessarily be some time lag between the lobbying activity and the time when information became available on participants' incentives. This lag would arise due to the time required to identify lobbying, trigger a disclosure requirement, and for the participant to collate and provide information. This lag may only be a week or two, but would tend to undermine the effectiveness of disclosure; and

- historical experience suggests that parties which are significantly exposed to spot prices tend to argue that hedge contracts were not available, or that terms were unattractive. The strength of these arguments is difficult to assess without information on comparable organisations – such as the net position of other large industrial users or hydro-generators. Under a targeted disclosure regime, such comparator information would not be readily available.

143. For these reasons, a broader disclosure regime is favoured over the more targeted approach. The key features of the proposed regime are set out in Table 4[60].

Table 4: Key features of disclosure mechanism

Item	Proposal
Nature of obligation	Defined parties would be required to disclose either: • a pre-defined measure of net exposure to spot prices (e.g. net purchase/sale position in GWh); or • sufficient information for the Authority to calculate a party's net exposure to spot prices
Audit	The Authority would have a right to audit information supplied under a disclosure obligation
Parties covered	The obligation would apply to: • parties who purchase energy from, or sell energy to, the Clearing Manager; and • any other parties who buy or sell hedge contracts and are Participants under the Code A de minimis provision could be applied to reduce or relax obligations on smaller parties
Frequency	Parties would be required to provide regular disclosures (for example quarterly) and interim period updates could also be requested by the Authority
Publication of information	The Authority would receive information from individual parties covered under the disclosure obligation. The Authority would prepare and publish a summary report from this information. The summary would provide sufficient information to indicate which parties would be expected to benefit financially from public conservation campaigns.

60 The disclosure regime described in the table is specifically designed to address concerns about public conservation campaigns. The Authority is currently initiating work to review wider disclosure and information arrangements. In particular, it will consider the potential benefits of improved disclosure for its market and industry monitoring functions, and in management of prudential risk. It is possible that this will lead to initiatives that complement or modify the proposed regime in the table.

Q8. What is your view of the proposed disclosure mechanism?

5.5.2 Financial mechanisms

144. The disclosure approach operates by facilitating greater scrutiny of parties' motives in calling for campaigns. An alternative approach would be to counter the incentive for some parties to under-hedge and instead seek to reduce their risk by lobbying for campaigns.

145. One possibility would be a set of graduated penalties to be applied to spot market purchasers based on their actual or simulated net exposure to spot prices over the preceding quarter or year. The penalties could be applied when average spot prices for a defined period fall below pre-defined levels, as that is when purchasers are tempted to do without hedges, or they could be applied at regular intervals regardless of market conditions.

146. This approach would encourage hedging, directly reducing incentives for spot market purchasers to lobby for public conservation campaigns when supply risks are minimal (but spot prices are high to entice last resort generation into the market).

147. Higher hedging levels would also reduce incentives on net purchasers with discretionary generation to suppress prices in the near term (as discussed in paragraph 69). It would also reduce the need for last resort generators to earn large margins over their short run marginal costs from the spot market, as a larger share of their fixed costs would be covered by hedge contracts. This should increase confidence in the competitiveness of spot market prices, which would flow through to lower hedge prices, which in turn encourages greater hedging activity.

148. Another financial mechanism would be a floor price when public conservation campaigns are operating. The trigger point for starting a public conservation campaign is hydro storage[61] falling below the 10% risk curve[62]. By implication, at this point the expected benefit from commencing a campaign (in terms of a reduced probability of subsequent shortage etc) is sufficient to offset the expected societal cost.

149. Simulation techniques can be used to estimate the expected value of electricity (i.e. expected benefit in terms of reduced shortage cost) at the 10% risk curve. This analysis has been undertaken and indicates an expected value of approximately $500/MWh at the 10% risk curve (see Appendix E for more detail). This suggests that if a floor price were to be applied during public conservation campaigns, the value would be approximately $500/MWh.

150. It would also be important to consider the method of applying any floor price, especially whether it would apply for all trading periods during a public conservation

[61] Although the trigger is framed in terms of hydro storage, thermal fuel availability is also important and is taken into account in calculating the position of the risk curves. The trigger for ceasing a campaign is that storage recovers above the 8% risk curve.

[62] See www.ea.govt.nz/consumer/customer-compensation-scheme/ for more detail.

campaign. From an economic perspective, it would not make sense to apply a floor in trading periods when the value of savings was below the floor level. For example, this might be the case during off peak periods when demand could be satisfied by must-run generation[63]. Likewise, it would be important to consider the treatment of nodal price effects with any floor. These types of issues mean that a floor price would involve some degree of implementation complexity.

Q9. What is your view of these possible financial mechanisms?

151. In assessing alternatives for evaluation, it is important to note that the Act requires that the Authority consider imposing "a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including public conservation campaigns)"[64].

152. Moreover, the Authority believes it should measure net exposure to spot prices before pursuing a penalty regime, as it is important to assess the size of the incentive effects at play. It is also likely that a disclosure mechanism would encourage greater hedging activity, if participants perceive that a penalty regime may follow. The next section therefore compares the price floor mechanism against the disclosure mechanism.

5.5.3 Comparison of disclosure and financial mechanisms

153. A broad comparison of the disclosure and financial mechanisms is set out in Table 5.

Table 5: Comparison of disclosure and financial mechanisms

Criteria	Disclosure mechanism	Financial mechanism
Effect on reliability	Should reduce incentive for parties to 'talk up' security risks and over-use public conservation campaigns Should provide more efficient levels of supply reliability. However, may not entirely address issue where a party can obtain significant financial benefit from conservation	Should provide more efficient levels of supply reliability, provided the price floor is durable and is set at a level that reflects expected societal cost of campaigns May not eliminate incentive to lobby for campaigns, particularly as parties long on generation may now have incentives to

63 Generally speaking, during energy or fuel shortages (when a public conservation campaign is most likely to be invoked), the differential between day and night prices reduces. This was evident for example in 2008 in the South Island when intra-day price differentials narrowed significantly. Given that public conservation campaigns will in future not be instituted until a latter point (a 10% risk of shortage), the likelihood of intra-day differentials being evident should be further reduced. This suggests that a relatively simple floor price mechanism might be feasible – but this would require further consideration.

64 Section 42(2)b of Electricity Industry Act 2010.

	campaign	lobby for them
Effect on competition	Not clear – if it leads to greater hedging activity it could increase competitive pressure in the spot market and subsequently in the hedge market. May potentially alter competitive position for some parties depending on form	Not clear – entry by stand alone retailers or non-portfolio generators may be inhibited if they are unable to obtain/sell adequate hedge cover.[65]
Effect on operational efficiency	Increased disclosure unlikely to have adverse effect on the efficient operation of the electricity industry, since the obligation does not directly constrain participant choices about demand level, generation dispatch or investment	A price floor that is too low is not expected to have any material effect on dispatch (positive or negative), but would not disincentivise lobbying A price floor that is too high is expected to have an adverse impact – though effect not expected to be large unless floor is mis-estimated by significant margin (see Appendix E)

154. In summary, both mechanisms would be expected to provide more assurance about reliability. Arguably, the assurance is higher for the financial mechanism, provided the level of the price floor can be estimated with reasonable confidence and provided it is durable. However, offsetting this potential advantage, the disclosure mechanism has lower potential to cause unintended adverse outcomes, because it would not directly alter participant choices about physical demand and supply.

155. Lastly, the two mechanisms are not mutually exclusive, especially as improved disclosure might yield benefits in other areas (for example in the context of market monitoring) and in providing information to stress test market arrangements.

Q10. What is your view of the comparative merits of disclosure versus a spot price floor to address concerns about over-reliance on public conservation campaigns? Is there merit in pursuing both mechanisms?

65 There is also a possibility that the price floor may chill competition in the hedge markets as the review dates approach for each three yearly reviews. However, the proposed 12 month lead time before any material change takes effect should reduce this risk, as well as the clear framework for assessing changes provided by the statutory objective.

5.6 Geographic extent of shortage to trigger scarcity pricing

156. The New Zealand wholesale electricity market operates on the basis of nodal pricing. Scarcity prices could be applied to shortage events affecting a single node (‘node threshold’), or be limited to events that only affect the wider areas (e.g. a minimum region, island, or national threshold). The decision on which threshold to apply depends on the relative benefits, costs and risks of the different options[66].

157. As discussed in Appendix D, scarcity pricing is intended to provide signals which facilitate efficient investment and operating decisions. It is not clear that a scarcity price signal for single node shortage events would improve economic efficiency in many such ‘local’ scarcity situations. This is because in many instances, shortage events affecting a single node or localised area are primarily driven by transmission-related actions, but transmission decision-makers[67] are not currently exposed to the nodal price consequences of these choices.

158. The adoption of scarcity pricing for shortages at individual nodes is also likely to increase locational price risk, which could in turn impede competition in the retail and hedge markets. While new mechanisms are being considered to facilitate the management of locational price risk, these are expected to focus initially on inter-island risk. Furthermore, even if locational price risk management tools were widened to include intra-island risk, the net effect on risk would depend on the precise design and participants would be likely to require some time to become familiar with new tools. In the meantime, there would be a potential for actual or perceived locational price risk to impede competition.

159. It is also important to note that from an implementation perspective, the degree of complexity is likely to be higher for the regional options. This is because existing processes are based on nodes (prices for active energy) or islands (prices for SIR and FIR), and can easily use these as starting points.

160. Ultimately, the choice of minimum geographic threshold is a matter of judgement. In light of the Authority’s preference for lower risk, scalable options and pro-competitive measures, it is proposed that a minimum geographic threshold of an *island* curtailment event be adopted at the outset. Likewise, this threshold would also apply to the use of a price floor during public conservation campaigns.

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66 There is a separate issue associated with nodal pricing, which is whether to apply transmission loss effects inside any geographic region affected by shortage. For example, if the entire North Island was experiencing shortage (and load restriction), should a uniform price apply at all nodes in the island? Alternatively, should nodal prices within the North Island vary to reflect ‘transmission losses’, so that prices would be higher in the upper North Island than the Wellington area (assuming northward flows). This issue is distinct from the question of minimum geographic thresholds for scarcity pricing, and will be addressed in the detailed implementation phase once an overall design is determined.

67 This is Transpower for operating decisions (e.g. when to take out assets for maintenance, what particular grid configurations to employ), and a combination of Transpower and the Commerce Commission in the case of investment decisions.

161. The intention is to reassess this boundary in future periodic reviews (see below), allowing the boundary to be progressively relaxed if there are expected net benefits. This will also allow experience to be gained with other potentially relevant initiatives, such as the proposed introduction of new locational price risk management tools, and possible changes to transmission pricing methodologies.

Q11. What is your view of the proposed approach to imposing a minimum geographic threshold before any scarcity price floor is applied?

5.7 Transition and review provisions

5.7.1 Phase-in provisions

162. The introduction of scarcity pricing would be a significant change to current arrangements, and it is important that market participants have sufficient lead time to understand the changes, and make any necessary adjustments to their plans. In particular, it would be desirable to ensure that participants have sufficient time to ensure that they are able to be highly hedged prior to the introduction of scarcity pricing. This should increase the durability and credibility of any Code changes, which is a very important consideration in the design of scarcity pricing arrangements.

163. These factors suggest that transition arrangements should be included, provided this does not carry an undue risk of compromising security. In this context, the following factors appear to be relevant:

- the reserve energy scheme ended after 31 October 2010. While this has improved incentives for the market provision of resources, it also means the system is more reliant on spot prices to provide appropriate signals in supply emergencies;
- the capacity offer price for the Whirinaki power station has been administratively determined, and is currently at $5,000/MWh[68]. This offer has had an effect that is similar to a scarcity price of $5,000/MWh (although unlike a true scarcity price, the offer price applies to any Whirinaki output, rather than in forced load shedding situations). The Government has announced the intended sale of Whirinaki power station, at which point the offer price will be determined by the owner, rather than set by the Authority on an administrative basis;
- the capacity of the HVDC link is currently constrained and this may complicate risk management decisions for industry participants. All other things being equal,

[68] The Electricity Authority is currently consulting on the capacity offer price for Whirinaki and has proposed that it be reduced to the plant's short-run marginal cost, once it is confirmed that sufficient capacity will be available to the System Operator to meet demand. See Consultation Paper, "Capacity Offer for Whirinaki", *Electricity Authority,* 1 March 2011

it could be preferable to defer the full introduction of scarcity price changes until the HVDC capacity has been increased (i.e. until after mid-2012); and

- a phased introduction should not materially affect investment decisions (since these are forward looking), but could affect operational decisions such as unit commitment choices and fuel management decisions.

164. In light of these factors, it is proposed that some transition should be provided. There appear to be three broad approaches which could be followed:

- staged introduction of individual measures;
- adopt the whole package of changes, but increase the scarcity price floors over time; and/or
- adopt the whole package (including disclosure) with full scarcity price values, but moderate the impact of price floors with a 'stop-loss' type mechanism that is progressively relaxed over time.

5.7.2 Staged introduction of package elements

165. The Authority has considered the possibility of proceeding first with the capacity-related measures (i.e. the floor for emergency load shedding and pricing changes for IR shortfalls) along with information disclosure, and then moving to the energy-related measures.

166. The rationale for this approach is that the capacity-related measures are expected to be more straightforward to implement[69]. Furthermore, the introduction of scarcity pricing changes for capacity shortfalls would arguably raise fewer safeguard-related concerns because these events by nature have a shorter expected duration.

167. The principal drawback with this approach is that concerns about the potential for over-reliance on rolling outages and public conservation campaigns would not be directly addressed at the outset. However, this risk could be reduced by early adoption of the increased disclosure provisions discussed in Section 5.5.1. This should reduce the incentive for some participants to talk up security concerns in advance of a campaign. Increased disclosure would also allow the Authority to form a view about hedging levels, and the extent to which participants are relying on non-price interventions to manage their risk in an energy shortfall.

168. If a staged approach were to be adopted, it would allow for experience gained from the introduction of capacity-related scarcity pricing to be applied to arrangements for energy shortfalls. This experience, coupled with the information from increased disclosure, might alter the design of price floors for energy shortfalls, or even indicate that the other changes are sufficient.

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[69] In particular, they address situations where there is a resource deficit in real time. There is more ability to draw on international experience for these events, given that other scarcity price regimes focus on such issues. The energy-related measures are more complex because there are inter-temporal issues to consider, such as whether a price floor should be adjusted to take any intra-day effects into account.

5.7.3 Phased transition of whole package

169. An alternative approach considered by the Authority is to introduce all elements (including information disclosure) as a package, but to phase in scarcity price floors by increasing the respective values over time.

170. The main rationale for proceeding with the whole package is that energy-related shortfalls have been the dominant concern in New Zealand in the last decade. While the system appears to be moving toward a position where capacity constraints will become more important, energy shortfalls will remain as a credible risk. On this view, it would be desirable to advance measures across the spectrum to address capacity and energy-related issues simultaneously.

171. The phase-in profile for scarcity price values could be specified in detail. For example a two step phase-in profile could be defined, with initial values applying from (say) 1 April 2012, followed by an increase to the full values in April 2013.

172. Alternatively, a set of starting values could be defined, with subsequent increases being contingent on an assessment by the Authority. In this context, one of the key issues that the Authority would wish to assess is the effectiveness of hedging arrangements. The proposed disclosure of net spot exposures would materially assist in this respect. The ability to access comparative data would also help to identify whether any hedging issues are systemic or reflect choices by individual participants.

173. The major advantage of making transition contingent on further assessment by the Authority is that it would provide greater flexibility for any desirable ‘mid-course’ corrections and more scope to ‘ratchet up’ the effect of scarcity pricing as hedge market activity increases However, this benefit needs to be traded off against the potential advantages of greater certainty for participants if phase-in arrangements are more firmly defined beforehand.

5.7.4 Transitional stop-loss mechanism

174. Another approach would be to introduce the whole package of changes (including disclosure) with the full scarcity price values, but to moderate the effect of price floors with a ‘stop-loss’ type mechanism.

175. This mechanism would limit the application of a price floor beyond a pre-defined point. This limit could be specified in terms of a cumulative price threshold (see Appendix G for more detail) or a maximum duration for which a price floor could be applied. The intention would be to progressively relax the limit over time as participants adjust their risk management practices and gain experience with scarcity pricing.

176. As with the previous option, the transition profile for the stop-loss mechanism could be specified in advance, or be contingent upon ongoing assessments by the Authority.

5.7.5 Overall view on transition arrangements

177. At this point, the Authority does not have any firm preference in relation to transition arrangements. It also notes the possibility of combining aspects of the approaches discussed above. For example, it would be possible to proceed first with the capacity and disclosure measures, but to increase the scarcity price floor for emergency load shedding over time.

178. A key issue in selecting the path forward is the perceived effect on the durability and credibility of scarcity pricing arrangements. The Authority is conscious that these factors will be very important for scarcity pricing to have the desired enduring effect on incentives.

179. The Authority's objective is to identify the overall package of changes that will move electricity market arrangements toward the desired goal as swiftly as possible, while minimising the risk of ad-hoc intervention in a supply emergency. Obtaining stakeholder views on these matters will assist in identifying the package of measures that best balances these various considerations.

Q12. What is your view of the preferred approach to transition arrangements?

5.7.6 Ongoing review provisions

180. Another important issue is the process for reviewing scarcity pricing arrangements once they are in place. Such reviews are important because although analysis and modelling techniques shed light on issues such as the appropriate level for scarcity price values, there will necessarily be an element of judgement required. For this reason, it is important to provide a review mechanism to incorporate new information and experience with a scarcity pricing regime. It would also allow for modification to other matters, such as the minimum geographic extent of shortage to trigger scarcity pricing.

181. In principle, reviews could be handled under the normal Code amendment process. However, this allows for reviews at any time, and it is desirable to provide participants with more certainty if possible on these matters, given the impact on investment and operating decisions.

182. For this reason, it is proposed that formal reviews would be conducted at least every three years[70], and would cover scarcity price values and other key design issues. The review process would have the following features:

[70] As a point of comparison, the Australian NEM provides for two yearly reviews, with a two year lead time before changes can come into effect. Two years appears to be a relatively short time frame given the desire to promote stability. A three year lead time is suggested for New Zealand.

- possible changes to scarcity price values would be evaluated against a clear set of published criteria, which would be anchored in the statutory framework and Code;
- the process for initiating and/or considering possible changes would ensure that affected stakeholders can provide input before final decisions are made; and
- unless change is necessary to address a genuinely urgent issue, at least 12 months notice would be provided before any changes to scarcity price values take effect. This would assist in providing parties with time to adjust their plans and/or risk management positions, and reduce the risk of high prices arising from weak competitive pressure.

183. The Authority might also conduct a review at other times, for example after any event where widespread forced load shedding was required and price floors were operative.

Q13. What is your view of the proposed approach to review arrangements?

6 Analysis

Section summary

- Based on present information, the proposed changes are expected to be potentially consistent with the Authority's statutory objective
- The scarcity pricing proposal is estimated to have potential net economic benefits of approximately $95 million to $114 million when assessed against the counter-factual. Even if a more conservative counter-factual (with less price suppression) is assumed, the expected potential net benefit range remains positive at approximately $19 million to $24 million
- The Authority is also mindful that there are other measures that could complement scarcity pricing, relating primarily to hedging market arrangements. At this point, the Authority considers that the proposals in Table 1 are a good starting point and it will observe hedging behaviour to determine whether to consider additional measures to achieve robust security of supply arrangements

6.1 Objective of proposal

184. The objective of scarcity pricing is to provide greater assurance that the 'efficient' level of security and reliability will be delivered by the electricity system. This is the level where the marginal benefit of increased security and reliability equals the marginal cost of achieving it.

185. For the reasons outlined earlier, the Authority believes that current arrangements are unlikely to yield this outcome, and that the system will tend to undershoot the efficient level of reliability and security. As a result, there is a greater likelihood of forced demand curtailment occurring, and more frequent 'near miss' events such as shortfalls in instantaneous reserve cover.

6.2 Assessment against the Authority's statutory objective

186. The statutory objective of the Authority is to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers"[71].

187. The Authority considers it useful to break-down its statutory objective into three limbs, as follows:

- Limb 1: promoting competition in the electricity industry for the long-term benefit of consumers;
- Limb 2: promoting reliable supply by the electricity industry for the long-term benefit of consumers; and
- Limb 3: promoting the efficient operation of the electricity industry for the long-term benefit of consumers.

[71] Section 15 of Electricity Industry Act 2010

6.2.1 Limb 1: Competition in the electricity industry

188. The core objective of scarcity pricing is to improve the reliability of supply (i.e. Limb 2 discussed further below) rather than to promote competition. Nonetheless, it is important to consider whether scarcity pricing could have unintended adverse impacts on competition in the electricity industry.

189. As stated by the Authority:

> "*The Authority therefore interprets the phrase competition for the long-term benefit of consumers to mean it should consider the incentives for buyers and sellers to enter and exit the market, barriers to entry and exit, and more generally the contestability of the various markets in the electricity industry. This includes considering the long term value gains for consumers when market arrangements are conducive to entry by innovative suppliers and conducive to efficient investment*"[72]

190. In the current context, the key issue is the extent to which the introduction of scarcity pricing including the possibility of increased disclosure requirements could increase barriers to entry and exit within the various markets in the electricity industry. This issue needs to be assessed against a counter-factual of current arrangements, including changes that have yet to take effect. These include:

- phasing out the Reserve Energy Scheme, and the sale by the Crown of the Whirinaki reserve generation plant;
- restructuring some of the state owned enterprise generator-retailers by transferring assets and virtual asset swaps;
- establishing an open access trading vehicle for futures contracts and, if necessary, introducing a market maker initiative; and
- enhancing market information and monitoring.

191. Scarcity pricing is intended to reduce the potential for spot price suppression due to non-price administrative actions (such as forced demand curtailment) in supply emergencies.

192. To the extent that scarcity pricing alters spot prices during supply emergencies, it could be argued that this may create greater financial risk for market participants as it will tend to increase prices at times of system stress. This in turn could act as an impediment to competition, particularly for new entrant retailers or non-portfolio generators if they are unable to obtain reasonable hedge cover.

193. As noted in section 6.4.1, the introduction of scarcity pricing is not expected to alter the time weighted *average* wholesale price over the longer term. However, there may be some shorter term impacts as the system adjusts to a new equilibrium. Of itself, any such effect should not act as a barrier to entry or exit, provided changes are clearly signalled in advance and participants have time to adjust their plans.

[72] See "Interpretation of the Authority's statutory objective", *Electricity Authority,* 14 February 2011

194. Scarcity pricing could also change the *volatility* of spot prices. In this context, the proposed arrangements would be expected to narrow the range of possible price outcomes during IR shortfalls. For example, as noted in Appendix A, when IR shortfalls occur in dispatch, final prices could settle well above the highest supply offer. The proposed arrangements should narrow the range of possible outcomes in IR shortfalls (the most frequent form of supply emergency). The floor prices to be applied in actual load shedding could also narrow potential outcomes to an extent, relative to the counter-factual.

195. The preceding discussion focussed on spot prices in aggregate. It is also necessary to consider the effect of the proposed changes on locational price risk, given that earlier studies have identified a correlation between retailers' geographic footprints and locational price risk[73]. As discussed in Appendix D, were scarcity pricing to be applied to all demand curtailment events, it is likely that locational price risk would increase appreciably, relative to the counter-factual. However, given that scarcity pricing is proposed to only apply to widespread shortages affecting one or both islands, it is not expected to have any appreciable direct effect on *intra*-island locational price risk. To the extent that it has an effect on *inter*-island risk, this should be addressed by the proposed introduction of new locational price risk hedging instruments between the islands.

196. Another point to consider is whether scarcity pricing would alter the incentive on market participants to seek to raise prices at times. For example, the existence of a predefined scarcity price could arguably encourage parties with net seller positions to withhold capacity[74] to obtain higher revenues. However, this assumes there is no short term competitive response (i.e. through parties increasing generation output or demand side response to capture excess rents), which appears somewhat implausible on a sustained basis. Competitive responses can also occur over longer timeframes, such as investment in new generation, increasing hedge levels and investing in more demand response capability.

197. In relation to the possible disclosure of net spot exposures, this could encourage greater hedging activity, which could increase competitive pressure in the spot market and subsequently in the hedge market. However, there is also a possibility that disclosure may place some parties at a commercial disadvantage. For example, a party seeking to buy hedge cover might be disadvantaged by disclosure of its overall hedge position. The balance between these effects is uncertain and will depend on the details of any scheme, but it appears unlikely that disclosure would have a material adverse effect on competition.

198. Lastly, it is important to note that the Authority is pursuing other initiatives outside the scarcity pricing arena that have a pro-competitive intent. These include support for open access trading of futures contracts, more active market monitoring by the Authority, and facilitating greater demand-side participation. These should reduce the

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[73] See "Interpretation of the Authority's statutory objective", *Electricity Authority,* 14 February 2011.

[74] By reducing offered quantities and/or increasing the offer prices for existing quantities.

scope for any unintended adverse competition effects to arise from the introduction of scarcity pricing or disclosure.

199. In conclusion, provided purchasers, new entrant retailers and stand-alone generators are able to obtain reasonable hedge contract cover, the proposed changes should not have a material adverse effect on competition relative to the status quo[75]. However, even with existing initiatives to strengthen the hedge market, some questions remain about the effectiveness of hedging arrangements. The overall effect of scarcity pricing on competition therefore has some uncertainty.

6.2.2 Limb 2: Reliable supply by the electricity industry

200. As stated by the Authority:

> "*The benefits of reliable supply are the avoided costs of supply interruptions and quality degradation, and the avoided costs of under-investment by electricity users arising from investor uncertainty (avoided costs). Conversely, the costs of reliable supply are the costs of obtaining, operating and maintaining transmission, distribution and generation resources, and additional demand response capability, to cover short- and long-term risks in the power system (resource costs).*"
>
> "*Reliable supply is efficient when the marginal benefit of increased security and reliability equals the marginal cost of achieving it. The Authority therefore interprets 'reliable supply for the long-term benefit of consumers' to mean the efficient level of reliability, which occurs when the total of these costs is minimised.* [76]"

201. Under current arrangements, it appears unlikely that the efficient level of reliability will be realised. Instead, it is more likely that the system will on average provide a lower level of reliability. This can manifest itself through unduly tight supply margins (under-investment), and/or sub-optimal operating decisions (having sufficient plant, but not utilising it efficiently). In either case, electricity users will experience more near misses or actual shortages than is desirable.

202. As set out in Section 4, the reason sub-optimal reliability is expected is that current arrangements rely on spot price signals to ensure appropriate investment and operating decisions by providers of demand side response and by suppliers. However, during supply emergencies, price signals are likely to be suppressed on average. Furthermore, price outcomes are uncertain and can vary markedly according to exact conditions. The uncertainty effect is compounded by the possibility of an ad-hoc policy change in response to a major adverse event. These factors combine to undermine the incentives to provide the resource necessary to achieve the efficient level of reliability.

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75 Such a conclusion would not hold if scarcity pricing were to be applied at a geographical level less than the currently proposed island level, given that it would increase the intra-island locational price risk but parties would not have ready access to hedging instruments to manage such risk.

76 See "Interpretation of the Authority's statutory objective", *Electricity Authority,* 14 February 2011.

203. The changes being proposed in the scarcity pricing context are intended to directly address these issues. In essence, the price formation process during certain supply emergencies would be changed so that a price floor is applied. In respect of instantaneous reserve shortfalls, price formation would remain largely unchanged, except there would be reduced potential for suppression or extreme prices to emerge when the market clearing engine is near the limit of feasibility. In all cases, the price outcomes would, on average, be expected to better reflect the expected costs arising from different classes of supply emergency. This in turn is expected to promote the achievement of a more efficient level of reliability.

204. The Authority has also noted the importance of arrangements that are durable and consistent over time. In interpreting its statutory objective, the Authority has stated:

> "*.. security and reliability arrangements need to be durable in the face of high impact, low probability events or the impending prospect of those events occurring (hereafter, 'adverse events'). Adverse events can reduce efficiency by creating uncertainty for investors as a result of reactive changes to regulatory settings*."
>
> "*The Authority therefore interprets the phrase 'reliable supply for the long-term benefit of consumers' to mean efficient levels of reliable supply, where efficiency includes dynamic efficiency gains from adopting time-consistent arrangements – that is, arrangements that are robust to adverse events over the longer term. In regard to minimising total costs, the Authority believes the potential costs of regulatory uncertainty and ad-hoc interventions should be taken into account in determining minimum total costs*." [77]

205. The Authority's proposals are also intended to reduce the risk of ad-hoc intervention during or soon after a supply emergency. First, by improving price signals, participants will have a stronger incentive to provide the resources (demand-response and supply) needed to achieve an efficient level of reliability. This should reduce the frequency of forced load shedding and 'near miss' events – which are major potential triggers for ad-hoc intervention.

206. Second, the changes will reduce the potential for spot price suppression during different types of supply emergency. Because the scarcity price values would be set through a public process and reviewed periodically, it should reduce the likelihood of ad-hoc price intervention during an emergency.

207. Another issue to consider is the risk that the proposed arrangements could make reliability worse – i.e. result in a higher overall total of avoided costs and resource costs. This possibility is considered unlikely for the following reasons:

- there is a possibility that scarcity values are set too high – in which case market participants would expend too much resource avoiding supply emergencies – relative to the true societal cost of those emergencies. While this possibility cannot be entirely discounted, the proposed scarcity values have been developed using an internally consistent framework. They also appear reasonable in relation to other

[77] See "Interpretation of the Authority's statutory objective", *Electricity Authority,* 14 February 2011

comparator data – for example the prices at which participants are prepared to offer demand-response on a voluntary basis;

- there is a possibility that scarcity values are set too low – in which case market participants would expend too little resource avoiding supply emergencies – relative to the true societal cost of those emergencies. Again, this possibility cannot be entirely discounted, but the same points as noted above also hold in this context. Furthermore, the scarcity values for load shedding would be applied as price *floors*. This should significantly reduce the potential for scarcity pricing to inadvertently suppress spot prices; and
- the Authority recognises that it will be important to review scarcity pricing in light of experience. For this reason, it intends to review the key design elements at least every three years. This should further reduce the risk that scarcity pricing arrangements will cause reliability to deteriorate, relative to the counter-factual.

208. In light of these factors, the Authority considers that the proposed scarcity pricing arrangements will contribute to meeting the reliability limb of its statutory objective.

6.2.3 Limb 3: Efficient operation of the electricity industry

209. As stated by the Authority:

> "*Overall then, the Authority interprets limb 3 as providing an over-riding efficiency criterion for the Authority's decisions in respect of any aspect of the electricity industry within the Authority's functions in section 16 of the Act*".
>
> "*In summary, the Authority interprets the phrase promoting efficient operation of the electricity industry for the long-term benefit of consumers to mean: Exercising its functions in ways that increase the efficiency of the electricity industry, taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation*[78]".

210. As noted earlier, the aim of the Authority's proposal is to provide greater assurance that the efficient level of security and reliability will be delivered by the electricity system. 'Efficient' in this context is defined as the level where the marginal benefit of increased security and reliability equals the marginal cost of achieving it. For this reason, the intended outcome is consistent with the efficient operation limb of the statutory objective.

211. The Authority acknowledges that there are uncertainties around the estimation of scarcity price values and other key parameters. Nonetheless, for the reasons discussed in paragraph 207, it believes that the proposed changes are likely to yield improved outcomes, relative to the counter-factual.

212. Finally, the Authority has considered whether the efficiency gains from the proposed changes will be shared with consumers. The Authority notes that consumers

[78] See Interpretation of the Authority's statutory objective", *Electricity Authority,* 14 February 2011

ultimately bear the costs of adverse outcomes under current arrangements, in the form of increased risk of load shedding (via forced cuts or in response to conservation campaigns and degraded security during instantaneous reserve shortfalls). The proposed changes are designed to address these issues.

213. In conclusion, the Authority believes that the proposed changes will contribute to meeting the efficient operation limb of its statutory objective.

Q14. What is your view of the proposed changes when assessed against the Electricity Authority's statutory objective?

6.3 Other reasonably practicable option

214. The previous section concluded that the proposed changes would be potentially consistent with the Electricity Authority's statutory objective. This section considers whether there are other options that would be *more* consistent with the Authority's statutory objective.

215. It considers an alternative reasonably practicable option of not proceeding with scarcity pricing, and instead introducing a form of capacity mechanism.

Q15. What, if any, other reasonably practicable options should be considered?

6.3.1 Capacity mechanism

216. Scarcity pricing seeks to improve reliability by strengthening the incentives on market participants to avoid or better manage supply emergencies. This includes actions such as entering into hedge contracts (which can fund generation), undertaking voluntary demand response, and investing in new supply or demand response capability. While scarcity pricing is expected to improve incentives, there is no absolute assurance that market participants will respond to these signals.

217. It is possible that they will discount the likelihood of a scarcity price signal being applied in practice. Market participants will be aware that policy makers can face strong pressures to intervene in an ad-hoc manner during or after supply emergencies – to address perceived physical security risks, and/or the high spot prices that accompany such events. Furthermore, parties adversely affected by high spot prices during a supply emergency may allege that they arise from weak competitive pressures rather than genuine scarcity, and it can be difficult to assess such claims.

218. If market participants discount the likelihood of scarcity pricing being applied, they will be less likely to take the appropriate actions in advance of, or during, supply emergencies: generators and demand response providers are less likely to invest

ahead of time given the uncertainties of realising revenue from high spot prices, and wholesale buyers are likely to hedge to a lower level.

219. It is also important to note that supply emergencies are relatively rare. This makes it more difficult for policy makers to build up a track record of credibility which can act as a guide for market participants.

220. To counter these risks, some jurisdictions have capacity mechanism arrangements that constrain participants' risk management choices. While the details of these regimes differ, they generally share the following features:

- wholesale market buyers are required to hold hedge contracts or firm generation capability to meet a pre-determined minimum proportion of their expected future demand; and
- generators are limited in their ability to sell firm contracts to ensure they do not become over-committed.

221. A number of capacity mechanisms have been adopted internationally to ensure adequate reliability. The mechanisms vary in detail, but typically cover the following areas:

- define the nature and level of forward obligation – for example whether it covers capacity and/or energy requirements. The forward contracting obligation may be relatively short term (e.g. one year) or a number of years (to create stronger forward investment incentives);
- set out a method for determining projected demand, to account for forecast load growth and to allow for changes in market share among retailers;
- provide a method for rating generators as to their firm capability, to account for hydrology, wind patterns, thermal fuel risks, plant reliability, supply diversity etc;
- provide arrangements to allow demand side participants to opt out, to the extent that they have 'firm' demand response capability;
- define arrangements for monitoring and enforcing obligations, including penalties for non-compliance.

222. New Zealand's physical issues could make a capacity mechanism more complex in some respects. In particular, most overseas schemes focus on ensuring sufficient capacity to meet peak demand. In New Zealand, a scheme would also need to address dry-year energy adequacy. This could require assumptions about the future management of hydro storage lakes and thermal fuel stocks. A New Zealand capacity mechanism could also need to account for transmission constraints in determining the level of 'firm' supply that can be sold by each generator.

223. Although these sorts of design issues are important, they are not insurmountable as evidenced by the schemes operating in other countries. The key issue is whether a capacity mechanism would offer net benefits over scarcity pricing.

224. The Authority has assessed a capacity mechanism against its statutory objective, considering each of the three limbs. The Authority makes the following observations:

- ***Limb 1: promoting competition in the electricity industry for the long-term benefit of consumers***. Provided it is well designed, a capacity mechanism should not significantly alter competitive barriers for new entrants and/or non portfolio players. For this reason, it would not be expected to significantly affect competition relative to the status quo or scarcity pricing;
- ***Limb 2: promoting reliable supply by the electricity industry for the long-term benefit of consumers***. A capacity mechanism should be able to deliver similar reliability to scarcity pricing. Indeed, there is arguably a higher level of assurance given the more direct intervention. Furthermore, there should be less risk of ad-hoc intervention with a capacity mechanism because parties are highly hedged. This increases the expected durability of the regime in a large adverse event. The risk with scarcity pricing is that the regime will be changed or replaced during a major event if market participants are inadequately hedged. Offsetting these factors, a capacity mechanism may have a greater risk of increasing reliability above the efficient level because there is a somewhat higher level of prescription. This has been an issue that has been raised in relation to some overseas regimes; and
- ***Limb 3: promoting the efficient operation of the electricity industry for the long-term benefit of consumers***. Capacity mechanisms narrow the range of the risk positions available to generators (to avoid over-selling) and buyers (to avoid under-hedging). Arrangements are needed to measure participant positions and ensure that any necessary adjustments occur. These arrangements necessarily involve some degree of prescription (for example to define 'firm' generation or a 'firm' hedge). At the margin, this may make it harder for participants to adopt efficiency improvements and to innovate.

225. The Authority has also assessed a capacity mechanism against the following Code amendment principles[79]:

- ***Principle 4 – Preference for Small-Scale 'Trial and Error' Options*** – a capacity mechanism would require significant changes to a number of aspects of the wholesale market and would not be regarded as incremental in nature. The introduction of scarcity pricing would also involve material change, but the scale is expected to be somewhat less than for a capacity mechanism;
- ***Principle 6 – Preference for Market Solutions*** – a capacity mechanism and scarcity pricing would both supplant market arrangements to some extent;
- ***Principle 7 – Preference for Flexibility to Allow Innovation*** – while some flexibility or opt out features would be possible (and desirable), there would need to be a basic level of prescription with a capacity mechanism. This could constrain or slow the process for adopting innovations; and

[79] See "Consultation Charter", *Electricity Authority*, *December* 2010

- ***Principle 8 – Preference for Non-Prescriptive Options*** - capacity mechanisms would by nature require a degree of prescription about some issues (for example the extent to which buyers must hold capacity tickets relative to their expected demand) [80]. The degree of prescription is expected to exceed that required for scarcity pricing.

226. Overall, it appears that a capacity mechanism could offer similar reliability benefits to scarcity pricing. Indeed, it may be superior relative to scarcity pricing and the status quo, when the risk of ad-hoc intervention during a large adverse event is taken into account.

227. However, a capacity mechanism is also likely to require somewhat more prescription than scarcity pricing. This may constrain or slow the process for adopting innovations. Over time, this may reduce the efficiency of operation of a capacity mechanism relative to the alternatives.

228. In conclusion, based on current information, the Authority considers that the scarcity pricing proposals in Table 2 are preferable to introducing a capacity mechanism at this time.

229. The Authority is also mindful that there are other measures that could complement scarcity pricing, relating primarily to hedging market arrangements. At this point, the Authority considers that the proposals in Table 2 are a good starting point and it will monitor hedging behaviour to determine whether to consider additional measures to achieve robust security of supply arrangements.

Q16. What is your view of a capacity mechanism, when assessed against the Electricity Authority's statutory objective?

6.4 Benefits and costs of proposed changes

6.4.1 Framework

230. An analysis has been undertaken of the costs and benefits that are expected to arise with the proposed changes. The details of the analysis are set out in Appendix F.

231. The analysis draws on the framework developed by the New Zealand Institute of Economic Research (NZIER) for the Electricity Commission[81]. Consistent with the Electricity Authority's statutory objective, the analysis is undertaken from an economy-wide perspective, weighing costs and benefits to New Zealand as a whole.

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80 For example, Professor W Hogan has noted that "*In the United States experience, resource adequacy programs designed to compensate for the missing money create in turn a new set of problems in market design. The resource adequacy approaches become increasingly detailed and increasingly prescriptive to the point of severing the connections between major investment decisions and energy market incentives*"

81 See An integrated cost-benefit analysis of the market development programme – Working Draft, *New Zealand Institute of Economic Research*, 2010

232. The Authority has not, at this time, taken a view on the durability of energy-related scarcity prices, as it wishes to obtain submitter feedback on the matter before doing so. If durability is doubtful then the costs and benefits of the regime may differ substantially from those indicated below. The Authority is intending to consult on its preferred option in July, and will take durability into account in its cost-benefit analysis at that stage.

233. Wealth transfers between parties, although affecting the distribution of costs and benefits, offset each other in the aggregation of total costs and benefits to New Zealand (i.e. where a cost to one party is an equivalent benefit to another party).

234. While effects which are solely transfers have not been included as costs or benefits from a national perspective, the Authority has considered the potential impact of scarcity pricing measures on prices and costs to electricity users. This issue is discussed in section 6.5.

235. The assessment of incremental costs and benefits has been considered against a counter-factual scenario of existing arrangements plus committed changes which have yet to take effect. These include:

- phasing out the Reserve Energy Scheme, and the sale by the Crown of the Whirinaki reserve generation plant;
- restructuring some of the state owned enterprise generator-retailers by transferring assets and virtual asset swaps;
- establishing an open access trading vehicle for futures contracts and, if necessary, introducing a market maker initiative; and
- enhancing market information and monitoring.

236. The counter-factual scenario reflects current pricing arrangements, and assumes that the highest supply offer is $3,500/MWh. This figure reflects observed generator offers in the past (see Appendix F for more detail).

237. An alternative counter-factual has also been considered. This assumes that the highest supply offer is $5,000/MWh, and is based on the capacity offer for Whirinaki which has applied from March 2010. This is a more conservative counter-factual, given that the Government has announced the sale of Whirinaki (at which point the offer price will be market determined). Furthermore, the Authority has proposed that the Whirinaki offer price will be reduced to the plant's short run marginal cost (subject to certain pre-conditions) until the sale takes place[82].

238. Estimates have been compiled of the expected benefit once the system has reached a steady state. In practice, benefits are unlikely to accrue immediately, and some phase-in should be allowed. For this reason, a range of scenarios have been considered where benefits of scarcity pricing are progressively realised over two,

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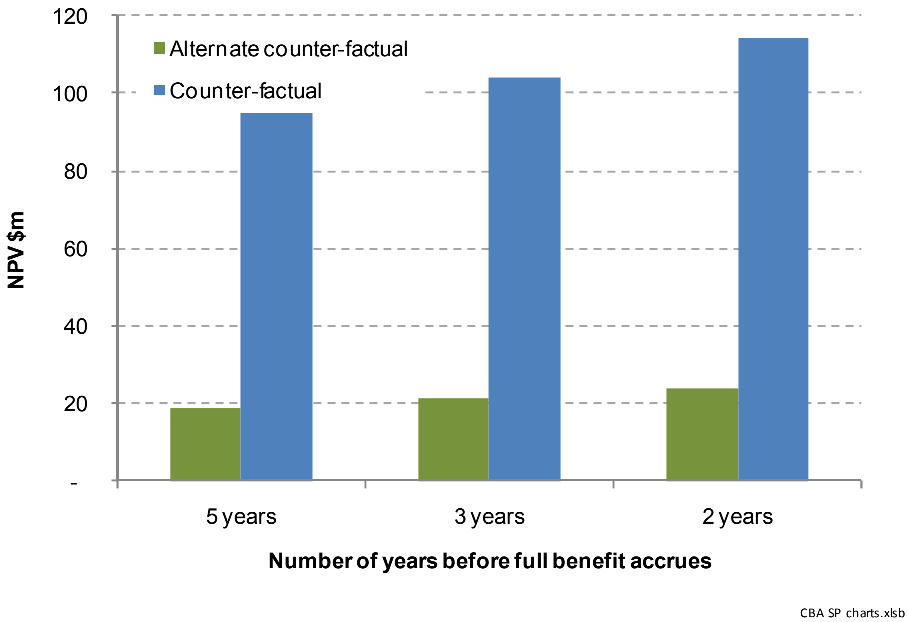
[82] The Electricity Authority has proposed that the offer price be reduced to the plant's short-run marginal cost, once it is confirmed that sufficient capacity will be available to the System Operator to meet demand. See Consultation Paper, "Capacity Offer for Whirinaki", *Electricity Authority,* 1 March 2011

three, or five years. This information has been combined with cost information to estimate the net present value of expected benefits.

239. The results of the analysis are summarised in Figure 4.

Figure 4: Estimated net benefits from scarcity pricing



240. When assessed against the counter-factual, scarcity pricing is expected to yield potential net economic benefits of approximately $95 million to $114 million, depending on the phase in period for benefits. Even if the more conservative starting position (with less price suppression) is assumed, the expected potential net benefit range remains positive at approximately $19 million to $24 million.

241. Finally, it is important to note these results are based on an assumption that scarcity pricing changes are durable and are perceived as such by market participants. To the extent that this assumption does not hold, the net benefits of the proposals would decline and could even be negative.

Q17. What is your view of the costs and benefits of the proposed changes?

6.5 Effect on electricity prices

242. As noted in the previous section, to the extent that scarcity pricing affects electricity prices, it could give rise to wealth transfers among different parties. These transfers could be between stakeholder types (e.g. from consumers to suppliers) and/or within stakeholder groups (e.g. from consumers with peaky demand profiles to those with more responsive demand).

243. While wealth transfers can affect the distribution of costs and benefits, they offset each other in the aggregation of total effects for New Zealand (i.e. where a cost to one party is an equivalent benefit to another party). For this reason, effects which are solely transfers have not been included in the national cost benefit analysis.

244. Nonetheless, the Authority has considered the potential for scarcity pricing to affect prices and costs for electricity users. To assess this issue, it has used a scenario based approach.

245. The analysis considers two different timeframes:

- static effect - this focuses on the initial effect of change. It assumes that market participants *do not anticipate or react* to the introduction of scarcity pricing in any way. Under these assumptions, there can be an initial change in the time-weighted spot price, and demand-weighted spot prices for users with different demand profiles. The static analysis focuses on the proposed changes to pricing in capacity shortfalls[83], since capacity adequacy appears likely to be the binding constraint for the system in the near term; and

- dynamic effect – this considers the potential effect once the system has adjusted to the introduction of scarcity pricing. In this case, it is expected that the *time-weighted* spot price will be the same, whether or not scarcity pricing is introduced, because it will be capped in either case by the cost of new baseload generation[84]. However, even though the average is expected to be unchanged, scarcity pricing could alter the *structure* of spot prices, with higher prices in peak periods and lower prices off-peak, thereby impacting on demand-weighted prices.

246. The key elements in the scenario approach are:

- estimate the expected number of hours that the system will be in different security states – i.e. normal market, instantaneous reserve shortfalls of differing levels, and forced load shedding. The estimated hours are based on an assumed capacity margin at the time scarcity pricing is introduced. This assumes a margin of around 100MW above the current standard[85]. The estimated hours for each state in the long run are based on the system being at the security margin on average;

- estimate the spot price that will prevail for each security state, according to whether the proposed scarcity pricing changes apply or not. As set out in section 6.4.1, two non-scarcity price cases are considered: 'Counter-factual and 'Alternate counter-factual'. The price shapes for all three situations (i.e. the scarcity pricing

83 A price floor for emergency load shedding, and an IR demand curve for determining prices in instantaneous reserve shortfalls.

84 In the long run, if the time weighted average exceeded the cost of new generation, this would be expected to attract new entry and put downward pressure on prices, which in turn would delay further new investment. The reverse position also holds. These observations refer to general tendencies over the longer term. Oscillations around the trend position would likely occur.

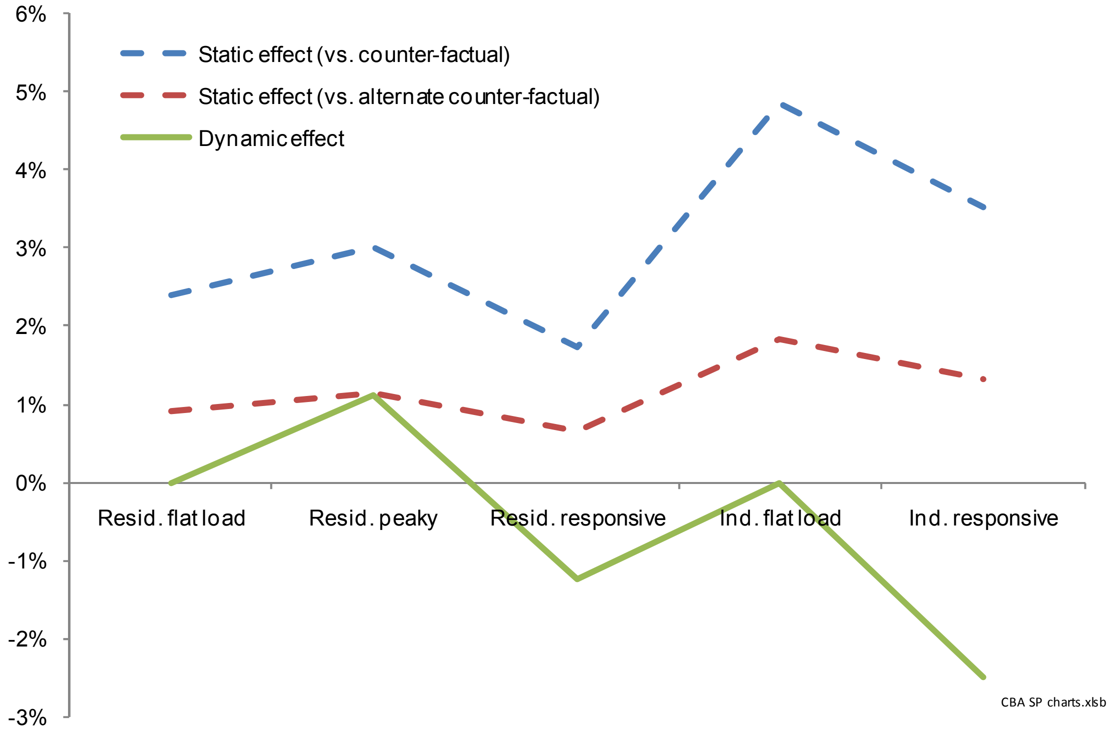
85 This is based on assumed introduction in mid-2012.

scenario, and the two non-scarcity pricing scenarios) are the same as those used for the derivation of scarcity price values, and are discussed in Appendix F; and

- determine the resulting average change in spot prices arising from scarcity pricing being introduced relative to the two non-scarcity pricing scenarios, and for different load profiles. This provides an estimate of the effect on wholesale energy costs for each case. These figures are then adjusted to reflect the proportion of the delivered electricity price which is accounted for by wholesale energy costs[86].

247. The results of applying this scenario approach are set out in Figure 5.

Figure 5: Scenario results – effect on mean electricity prices



248. The key observations from the scenario analysis are:

- the static effect is influenced by the starting point for change. Compared to the alternate counter-factual, the static impact is an increase of around 1-2% for mean delivered prices. If assessed against the counter-factual with no Whirinaki offer at $5,000/MWh, the effect is larger at 2-5%;

- the static effect varies by user demand profile. Demand profiles that are more peaky would be expected to experience a larger impact, relative to users with flatter or responsive profiles[87]; and

86 Data from the Ministry of Economic Development indicates that it is approximately 40% for residential users and around 82% for industrial users.

87 A user that can reduce load at times of higher prices.

- the dynamic effect varies according to user profile. Users with a flat profile would not be expected to experience any change in mean prices[88]. However, users with responsive profiles would be expected to see slightly lower prices on average, and those with peaky profiles to see slightly higher prices.

249. It is important to note these results are sensitive to assumptions about the starting point for change, and different user profiles. Furthermore, the static effects assume no behavioural response to scarcity pricing in any way. This is clearly a simplifying assumption and will tend to mean that the resulting price impacts are over-stated.

250. The potential impact of scarcity pricing on spot prices has arisen in the context of a proposed inter-island locational hedge product. In that context, the Authority engaged Energy Link to estimate the likely magnitude of inter-island loss and constraint excesses (which would be used to fund inter-island locational hedges) in future years. As part of its analysis, Energy Link considered scenarios with and without scarcity pricing. The results from Energy Link's scenario analysis were broadly consistent with those noted above, i.e. scarcity pricing is likely to alter the shape of spot prices (with higher prices when the system is tight and vice versa), but is not expected to have a material effect on the time weighted average price over time[89].

251. It is also important to note that projected price effects do not necessarily provide a full indication of wealth impacts, as these would be influenced by forward contract positions – at least for static effects. For example, while the static impact for an industrial user with a flat profile could be 1-5% (depending on starting position), this assumes that the user is completely unhedged at the time of the change. To the extent that it has entered into forward contracting arrangements, the effect on purchase costs would be expected to be lower (unless forward contract prices reflect the possible introduction of scarcity pricing).

252. Finally, it is worth reiterating that this section focuses on pricing impacts, and these do not necessarily reflect the full economic position associated with scarcity pricing (which is addressed in the cost-benefit analysis in section 6.4 above). For example, pricing impacts do not take into account any benefits associated with reduced curtailment risk, which can be a real economic benefit to consumers. Similarly, possible benefits associated with reduced peak demand growth could have reduced network investment implications in the long term, resulting in both reduced economic costs to New Zealand and reduced prices to consumers. However, such effects have not been considered in the above.

253. In summary:

- the short term price effect depends on the starting point for considering change. Compared to arrangements with a Whirinaki offer price at $5,000/MWh, the static effect is expected to be around 1-2% for mean delivered prices depending on

[88] As discussed, this is based on the expectation that the cost of new baseload generation acts as a cap on long term average prices.

[89] The Authority expects to publish the Energy Link report shortly as part of a package of papers on locational hedge products.

usage profile. If assessed against a situation with no Whirinaki offer at $5,000/MWh, the static effect is likely to be around 2-5%, depending on usage profile. In both cases, no allowance is made for existing forward contracts or behavioural responses, both of which are likely to moderate the short term price impact; and

- in the medium term scarcity pricing is not expected to affect the *time-weighted* spot price, because this will be capped by the cost of new baseload generation. The effect on individual users will vary, depending on the nature of their usage profile.

Q18. What is your view of the likely impact on prices of the proposed scarcity pricing changes, both in the near term (static effects) and over time (when parties can adjust their plans and behaviour)?

6.6 Overseas comparisons

254. A number of other jurisdictions with an energy-only electricity market[90] have adopted scarcity pricing. These include the Australian National Electricity Market (NEM) covering the eastern states, the National Electricity Market of Singapore (NEMS), and the wholesale electricity market operated by the Electricity Reliability Council of Texas (ERCOT). Further information on these markets is set out in Table 6. In each case, however, the scarcity price is an administered price and/or price cap regime rather than a price floor.

Table 6: Summary of scarcity pricing features in other energy only markets[91]

Market	Main features
Australia (National Electricity Market)	A single value is adopted for the value of lost load (now called the market price cap). If demand is curtailed, the spot price is set to the market price cap (currently A$12,500/MWh). In addition, there is a rolling 7 day cumulative price threshold of A$187,500. If this is triggered, a separate lower price cap is then applied. Generators are paid the cap price, even if their offer price is above the cap level. Generators may seek compensation if spot revenues don't cover their costs (though no instance of such payments has been identified). Reserves also face the same price cap. The market price cap is reviewed every two years.
National	Prices paid by purchasers are effectively capped at VoLL (currently

90 That is markets which do not have a specific capacity mechanism or separate payment for capacity availability.

91 The table reflects the position based on examination of public documents. Each of these markets is continuing to evolve, and some differences may arise between the positions reported in previous documents and current rules.

Electricity Market of Singapore (NEMS)	S$5,000/MWh). Purchasers pay the Uniform Singapore Electricity Price (USEP) which is the average of generator payments divided by total consumption. Prices paid to generators are capped at 0.9 * VoLL. This effectively operates as an offer cap. Prices paid to generators are calculated on a nodal basis. The USEP is set to VOLL if there is insufficient supply to meet forecast demand. The NEMS considered a cumulative price threshold, but a cumulative price threshold was not incorporated in the final design (the reasons are not known).
Texas (ERCOT)	The offer price cap has been increased in recent years and is now at US$3,000/MWh (~$4,000/MWh). However, this cap does not cover small generators with <5% of the generation capacity in the market, for whom no offer price cap applies. There also appears to be cap on market prices. Under the market rules, the mechanism that allows for 'scarcity' pricing during shortage conditions relies upon the submission of high-priced offers by smaller generators. The market rules include a provision termed the Peaker Net Margin ("PNM") that appears to be designed to measure the annual net revenue of a hypothetical peaking unit. Under these rules, if the PNM for a year reaches a cumulative total of US$175,000 per MW, the system-wide offer cap is reduced to the higher of US$500/MWh or 50 times the daily gas price index. It appears that the PNM only reached the threshold once in the last five years (2005).

7 Potential new safeguard mechanisms

Section summary

- The Authority has considered whether price capping mechanisms should be introduced alongside the proposed implementation of scarcity pricing. Having considered the issue, the Authority is concerned that such mechanisms could have unintended adverse consequences.
- The Authority considers that concerns about weak competition are more appropriately addressed by pro-competitive measures and enhanced market monitoring.
- In respect of the potential for high spot prices during exceptional unforeseeable events (e.g. a major natural disaster), the Authority believes this can be adequately addressed through existing provisions relating to undesirable trading situations.
- In light of these factors, the Authority considers that price capping mechanisms should not be introduced on a permanent basis. However, it sees merit in considering a stop-loss type mechanism (such as a cumulative price threshold) as a possible transitional measure.

255. The preceding sections focussed on the potential for spot price suppression during supply emergencies, with adverse consequences for security and reliability.

256. Concern has also been raised about the possibility that spot prices might 'over shoot' at times. In particular:

- concerns have been expressed that high spot prices might arise as a result of weak competitive pressure. For example, wholesale market suppliers might seek to contrive a scarcity situation to increase their revenues; and
- concerns have been raised that high prices could occur on a sustained basis as a result of an exceptional adverse event. It could be argued that some events are so rare and extreme that it would be unreasonable to manage them through normal price-based market processes. For example, a devastating earthquake that caused significant damage to electricity supply might fall into this category.

257. These concerns already exist to an extent under current arrangements, but may be increased if scarcity pricing is introduced. For this reason, it is important to consider whether new safeguard mechanisms should be introduced alongside scarcity pricing.

258. Such safeguard mechanisms could take two broad forms:

- qualitative measures, which seek to address the cause of high spot prices – for example pro-competitive measures; or

- quantitative measures, which directly affect prices, irrespective of the cause – for example caps or cumulative limits on the level of spot prices.

7.1.1 Qualitative safeguard mechanisms

259. The most direct way to address concerns about weak competitive pressure is the pursuit of measures to facilitate competition in the wholesale market.

260. The Authority is already undertaking or supporting a number of initiatives in this area. These include:

    - the introduction of a dispatchable demand product, which is designed to allow qualifying demand-side participants to be dispatched in a manner analogous to generation – increasing the potential for demand-side participants to 'contest' with generation in the wholesale market;
    - changes to demand-side bidding and forecasting arrangements which are designed to improve the quality of pre-dispatch price signals, and facilitate response by demand-side participants and competing generators, especially during periods of tight supply;
    - the introduction of a product to facilitate hedging of locational price risk between the North and South Islands. This should increase the scope for parties to enter into *energy* contracts, since locational price risk will be able to be separately hedged;
    - encouraging the development of a more liquid energy hedge market. This will facilitate a higher level of forward contracting, and reduce the scope and incentive for suppliers to seek to raise prices in the spot market.

261. The Authority will continue to pursue these initiatives, and will be exploring other options to reduce barriers to competition in the wholesale market.

262. In addition, under section 16(1)(g) of the Electricity Industry Act 2010, the Authority has a specific function to undertake industry and market monitoring. In fulfilling this function, the Authority has significant information gathering powers. For example, it can require a participant to provide any information, papers, recordings, and documents that are in its possession or control, and to make its staff available for interview. The Authority believes that this monitoring function and its associated information gathering capability should assist in identifying any systemic concerns about competition over time.

Q19. What further pro-competitive initiatives should the Authority be considering at this time?

263. An issue that is distinct from concerns about competitive pressure is the potential for very high spot prices to arise following an exceptional adverse event, such as a devastating earthquake. It could be argued that beyond some threshold of severity, it would no longer be appropriate to use market-based processes to allocate available

supply, and that some administrative alternative is more appropriate for a temporary period.

264. This is analogous to force majeure provisions in commercial contracts, where contracting parties' normal rights and obligations may be temporarily suspended in exceptional circumstances.

265. The treatment of prices in exceptional events is an issue under existing arrangements, but arguably becomes more important if scarcity pricing is introduced because mandatory load shedding could be in operation during such events.

266. One approach to managing this issue would be to utilise the existing provisions in the Code relating to undesirable trading situations. Under the Code, an undesirable trading situation means any contingency or event:

   (a) that threatens, or may threaten, trading on the wholesale market for electricity and that would, or would be likely to, preclude the maintenance of orderly trading or proper settlement of trades; and

   (b) that, in the reasonable opinion of the Authority, cannot satisfactorily be resolved by any other mechanism available under this Code; and

   (c) includes, without limitation

      (i) manipulative or attempted manipulative trading activity; and

      (ii) conduct in relation to trading that is misleading or deceptive, or likely to mislead or deceive; and

      (iii) unwarranted speculation or an undesirable practice; and

      (iv) material breach of any law; and

      (v) any exceptional or unforeseen circumstance that is at variance with, or that threatens or may threaten, generally accepted principles of trading or the public interest.

267. Under Section 5.2 of the Code, if the Authority finds that an undesirable trading situation is developing or has developed, it may take one or more of the following steps to correct it:

   (a) suspending, limiting or curtailing, an activity on the wholesale market, either generally or for a specified period:

   (b) deferring completion of trades for a specified period:

   (c) directing that any trades be closed out or settled at a specified price:

   (d) giving directions to a participant to act in a manner (not inconsistent with this Code, the Act, or any other law) that will, in the Authority's opinion, correct or assist in overcoming the undesirable trading situation.

268. While there are significant pre-conditions before the undesirable trading situation provisions can be invoked, it appears likely that an exceptional event which causes substantial disruption to normal trading would be covered. Assuming the threshold is met, the Authority would be able to temporarily modify or suspend normal market processes, and (if required) direct that trades be closed out or settled at a specified price.

269. In summary, the undesirable trading situation provisions would appear to provide sufficient powers to address an exceptional event[92], and ensure that scarcity pricing is not applied in an inappropriate situation[93].

Q20. Do you agree that the undesirable trading situation provisions could be invoked to address an exceptional event, and ensure that scarcity pricing is not applied in an inappropriate situation? If not, what changes should be considered in relation to the undesirable trading situation provisions?

7.1.2 Quantitative safeguard mechanisms

270. The safeguard mechanisms discussed above seek to address the underlying cause of high spot prices, either ahead of time (for example pro-competitive measures) or at the time (for example the undesirable trading situation provisions).

271. While this approach has the advantage of targeting underlying causal factors, it leaves some uncertainty about price outcomes. An alternative approach used in some markets is to directly limit the range of possible pricing outcomes. These markets generally apply one or both of the following:

- an overall cap on market prices in any single trading period. This can be implemented via an upper limit on offer values or on final prices, or (more commonly) both; and
- a cumulative limit on average spot prices over a rolling time period. This is intended to moderate spot price outcomes during a prolonged event, by reducing prices below the ‘standard’ price cap (though still above ‘normal’ prices).

272. Both mechanisms have been considered as potential ‘add on’ elements to a scarcity pricing regime in New Zealand (for more detail see Appendix G).

273. The main advantage of price capping mechanisms is that they could directly moderate financial risk for market participants. This may reduce the likelihood of ad-hoc intervention during or after a supply emergency. The key risk with this approach is that the price capping mechanism is set too low, and closes off options that are

92 Provided it falls within the definition an “exceptional event” in the Code.

93 For completeness, it should also be noted that section 40 of the Electricity Industry Act 2010 provides for the Authority to make urgent Code changes if required. Such changes can come in effect from any date after they are gazetted.

economically and practically viable. This would lower reliability, and be contrary to outcomes intended through scarcity pricing.

274. It is inherently difficult to assess the balance of these benefits and costs. A capping mechanism could reduce participants' risk exposure and therefore potentially lower the likelihood of ad-hoc intervention. However, to do so, it has to close off some high price outcomes. This in turn increases the likelihood that it will have the unintended effect of deterring some viable supply or demand response options.

275. Furthermore, it could also be argued that the existence of capping mechanisms might increase the likelihood of ad-hoc intervention during a supply emergency, because it provides a swift and effective tool for intervention – i.e. via lowering the price cap value.

276. The Authority has considered the introduction of capping mechanisms on a permanent basis, and assessed them against its statutory objective, considering each of the three limbs:

- ***Limb 1: promoting competition in the electricity industry for the long-term benefit of consumers***. The introduction of permanent price capping mechanisms would be expected to have mixed effects on competition. On one hand, it may preclude some competitive options from being viable. For example, providers of demand response may be willing to offer their resource to the market, but have a genuinely high opportunity cost. A price capping mechanism could preclude the participation of such resources by capping prices at an unduly low level. On the other hand, by more closely defining the range of price risks that participants could face, price capping mechanisms may (at the margin) improve conditions for new entrants and/or non portfolio participants. The relative extent of these effects is difficult to assess, and would be dependent on the form and level of any capping mechanism. While the precise effect on competition is difficult to gauge, it s not clear that capping mechanisms will promote competition;

- ***Limb 2: promoting reliable supply by the electricity industry for the long-term benefit of consumers***. As discussed above, a capping mechanism would narrow the range of possible pricing outcomes. This could moderate financial risk for market participants, and may reduce the likelihood of ad-hoc intervention during or after a supply emergency. This may facilitate longer term investment by market participants. However, capping mechanisms also carry a risk of suppressing prices which would undermine reliability and security. This risk is heightened for a capping mechanism applied on a permanent basis. Overall, while the precise effect on reliability is very difficult to gauge, it is not clear that capping mechanisms will promote reliability; and

- ***Limb 3: promoting the efficient operation of the electricity industry for the long-term benefit of consumers***. The key *potential* efficiency gain from a capping mechanism is a more stable investment environment, leading to a more 'optimal' level of reliability and security. However, as noted above, it is not clear that a price capping mechanism will yield incremental reliability benefits, given the considerable uncertainties involved.

277. The Authority has also assessed price capping mechanisms against the following Code amendment principles in its Consultation Charter[94]:

- ***Principle 4 – Preference for Small-Scale 'Trial and Error' Options*** – The introduction of scarcity pricing would be a material change to existing arrangements. The adoption of a cumulative price threshold as a transitional mechanism (as discussed in Section 5.7.4) could assist with the introduction of scarcity pricing by reducing the scope for unintended outcomes;
- ***Principle 7 – Preference for Flexibility to Allow Innovation*** – it is difficult to see how opt out or flexibility provisions could be included within price capping mechanisms without re-introducing the risks that a cap is designed to address; and
- ***Principle 8 – Preference for Non-Prescriptive Options*** – in setting a cap, it is necessary to balance the twin objectives of seeking to reduce market risk, while not unduly dampening the incentives to provide resources during supply emergencies. There is an unavoidable tension between these objectives, and price capping mechanisms will tend to prescribe the outcome that will be achieved.

278. In summary, the Authority is conscious of the potential for electricity consumers to be exposed to high spot prices when there is weak competitive pressure on suppliers. Price capping mechanisms could help to address this risk. However, for the reasons set out above, the Authority sees capping mechanisms as a relatively blunt instrument with a significant risk of unforeseen adverse consequences.

279. The Authority prefers to address concerns about weak competition through other avenues – notably measures to strengthen competition such as improving the hedge market and addressing barriers to entry. The Authority also notes that one of its statutory functions is to undertake industry and market monitoring activity. This provides a further safeguard against systemic movements in prices due to weak competitive pressure on suppliers.

280. In light of these factors, the Authority on balance considers that price capping mechanisms should not be introduced on a permanent basis. However, it sees merit in considering a stop-loss type mechanism (such as a cumulative price threshold) as a possible transitional measure.

Q21. What is your view of price capping mechanisms, when assessed against the Electricity Authority's statutory objective? Does your view alter if a mechanism such as a cumulative price threshold is applied on a transitional basis?

[94] See "Consultation Charter", *Electricity Authority*, December 2010

8 Authority's preferred option and proposal

281. For the reasons set out in Section 6, the Authority believes that the proposals in this paper:

- are potentially consistent with the Authority's statutory objective;
- are preferred over the reasonably practicable alternative described in section 6.3; and
- potentially yield positive net benefits.

8.1 Attachments

282. The following items are attached to this paper:

(a) Appendix A which lists specific matters on which the Authority seeks feedback;

(b) Appendix B which describes price determination under current arrangements;

(c) Appendix C which describes the effect of the customer compensation scheme on wholesale purchasers' incentives in a public conservation campaign;

(d) Appendix D which describes issues associated with different geographic thresholds for shortages, before scarcity pricing would be applied;

(e) Appendix E which describes how scarcity price values have been estimated;

(f) Appendix F which sets out information on the cost benefit analysis for scarcity pricing; and

(g) Appendix G which describes price capping mechanisms used in some other markets.

Appendix A Specific matters

The Authority seeks feedback on the issues and proposals discussed in this Consultation Paper. Parties are also invited to provide their views on the following specific questions:

Q1. To what extent is price suppression an issue with current pricing arrangements?

Q2. To what extent do you agree that the spot price suppression will adversely affect security of supply?

Q3. What is your assessment of historic security of supply performance, and the likely future performance under current arrangements?

Q4. What is your view of the proposed price floor to be applied in emergency load curtailment?

Q5. What is your view of the proposed treatment of load curtailment in AUFLS events?

Q6. What is your view of the proposed approach to pricing during IR shortfalls?

Q7. What is your view of the proposed price floor to be applied in rolling outage load curtailment?

Q8. What is your view of the proposed disclosure mechanism?

Q9. What is your view of these possible financial mechanisms?

Q10. What is your view of the comparative merits of disclosure versus a spot price floor to address concerns about over-reliance on public conservation campaigns? Is there merit in pursuing both mechanisms?

Q11. What is your view of the proposed approach to imposing a minimum geographic threshold before any scarcity price floor is applied?

Q12. What is your view of the preferred approach to transition arrangements?

Q13. What is your view of the proposed approach to review arrangements?

Q14. What is your view of the proposed changes when assessed against the Electricity Authority's statutory objective?

Q15. What, if any, other reasonably practicable options should be considered?

Q16. What is your view of a capacity mechanism, when assessed against the Electricity Authority's statutory objective?

Q17. What is your view of the costs and benefits of the proposed changes?

Q18. What is your view of the likely impact on prices of the proposed scarcity pricing changes, both in the near term (static effects) and over time (when parties can adjust their plans and behaviour)?

Q19. What further pro-competitive initiatives should the Authority be considering at this time?

Q20. Do you agree that the undesirable trading situation provisions could be invoked to address an exceptional event, and ensure that scarcity pricing is not applied in an inappropriate situation? If not, what changes should be considered in relation to the undesirable trading situation provisions?

Q21. What is your view of price capping mechanisms, when assessed against the Electricity Authority's statutory objective?

Appendix B Spot price determination under current arrangements

Purpose

B.1 This appendix examines the sensitivity of spot price outcomes during tight system conditions under status quo arrangements. It considers three cases where capacity was tight in the North Island in 2009 and 2010, and assesses the sensitivity of spot price outcomes to modest variations in demand.

B.2 A high degree of sensitivity would indicate that there is a greater likelihood that final prices (which are calculated after the event using actual metered data) will not reflect conditions as experienced during real time dispatch. In other words price suppression and/or uncertainty effects would be likely to be important.

B.3 To test the sensitivity of price outcomes the approach taken was to alter demand slightly from that actually metered during the trading period, given that, as set out earlier, there tends to be systemic factors which mean that actual metered demand used for final prices is less than that estimated during real time dispatch.

B.4 The three cases are based on real demand and supply data for situations where tight system conditions were experienced. In two of the cases studied, a reduction in instantaneous reserves (IR) cover did occur during real time (5 October 2009 and 6 September 2010)[95]. In the other situation, the system was tight but normal reserve cover was maintained.

B.5 In addition, a separate more detailed analysis of the sensitivity of price outcomes during IR shortfalls was undertaken for situations where the final price solution is close to the point of infeasibility.

B.6 The scenarios and simulations have been analysed using vSPD[96], a model that seeks to replicate the outcomes generated by the market clearing engine actually used for calculating settlement prices. The current dispatch and pricing arrangements have been applied to all cases[97].

Key observations

B.7 Based on the analysis, the following observations are made:

- for small IR shortfalls in real time (where reserves cover is reduced below normal levels), there is a reasonable likelihood that the IR shortfall will not be apparent in the final pricing process, since real time conditions tend to be

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95 Or would have experienced an IR shortage under the variable reserves implementation.

96 Vectorised Schedule, Pricing and Dispatch model developed by the Electricity Authority.

97 In mid 2010, the arrangements for price formation during IR shortfalls were changed. These new rules have nonetheless been applied to the October 2009 event.

more constrained[98]. In other words, the supply / demand balance tends to be 'tighter' at the time dispatch decisions are made (e.g. to curtail load or IR cover) than is the case once the final prices are run using actual metered demand;

- for the two cases analysed with near IR or small IR shortages, around 20MW of North Island demand reduction would have maintained the marginal energy offer ($1,000/MWh and $5,000/MWh respectively). Additional demand reduction would have resulted in rapid drop-off in prices in the range of $85-$90/MWh for each additional MW reduction up to about 80MW reduction. Thereafter, additional load reduction would have less impact on reducing prices;
- larger IR violations in real time increase the likelihood of final energy prices settling on the highest energy offers, or even higher. Indeed, final prices could be much higher than the highest energy offer (40 times or more) due to the interaction of the energy and IR markets and the way the Market Clearing Engine works to extract more energy and IR out of the system when conditions are tight
- if demand curtailment were implemented to restore normal IR cover during the dispatch process, then there is a high likelihood that the prices would move off the highest energy offers. As observed for the 5 October 2009 case, a 177 MW sustained instantaneous reserve shortage (SIR) shortage in real time would have translated into a 14 MW SIR shortage in final pricing. Therefore, if 177 MW of demand curtailment had been requested during real time (and been met or exceeded), there is a high likelihood that the final energy prices would not be based on the highest energy offer. As with the previous instances, there is a rapid drop-off region where additional demand reduction would have a large effect on reducing energy prices; and
- in all three specific scenarios that were studied, a range of around 60 to 80MW was observed between the highest energy offers and the mid-merit offers. When in this range, variations in demand have a large effect on the final prices.

B.8 The cases examined below focus mainly on the point of sensitivity between real time capacity shortage (either an IR shortfall or demand curtailment) and 'no shortage'. A further important point to note is the extent to which final prices will differ between IR shortages and demand curtailment.

[98] This is due to greater likelihood of any actual demand curtailment exceeding the "optimal" amount due to uncertainty in real time conditions as well as the discrete blocks in which demand is curtailed. Furthermore, real-time conditions tend to be more constraining due to within period issues such as five minute forecast loads, discretionary constraints and five minute ramp rates.

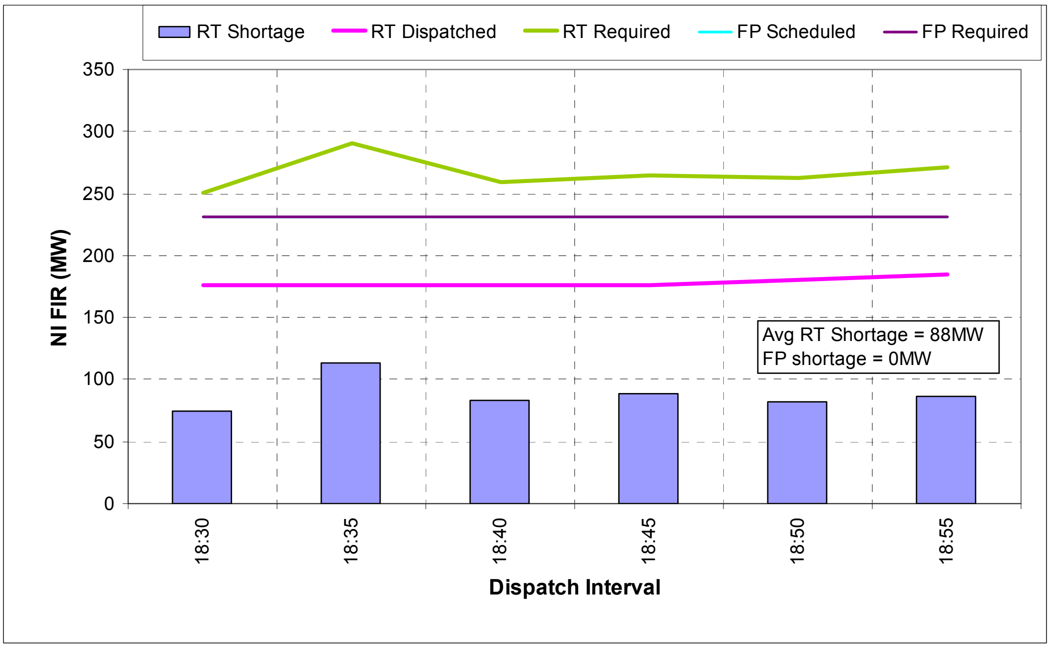
B.9 In practice, significant IR shortfalls are likely to yield similar price outcomes to demand curtailment situations, because final prices are expected to be based on the highest supply offer[99] in both cases.

5 October 2009 – TP38 (18:30)

B.10 The following analysis illustrates the potential shortages of North Island (NI) fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) that would have occurred on 5 October 2009 (18:30 to 19:00) for both the real-time dispatch and final pricing had the current variable reserves scheme been operating at that time. Due to the deviations between real time and final pricing, some instantaneous reserve violations experienced during real time are not replicated in final pricing. This illustrates the more constraining nature of the real time solve.

B.11 An average FIR shortage of 88 MW would have occurred during real-time dispatch for TP38. During final pricing no FIR shortage would have occurred. This is illustrated by Figure 6.

Figure 6: North Island Fast Instantaneous Reserve (real time and final pricing)[100]

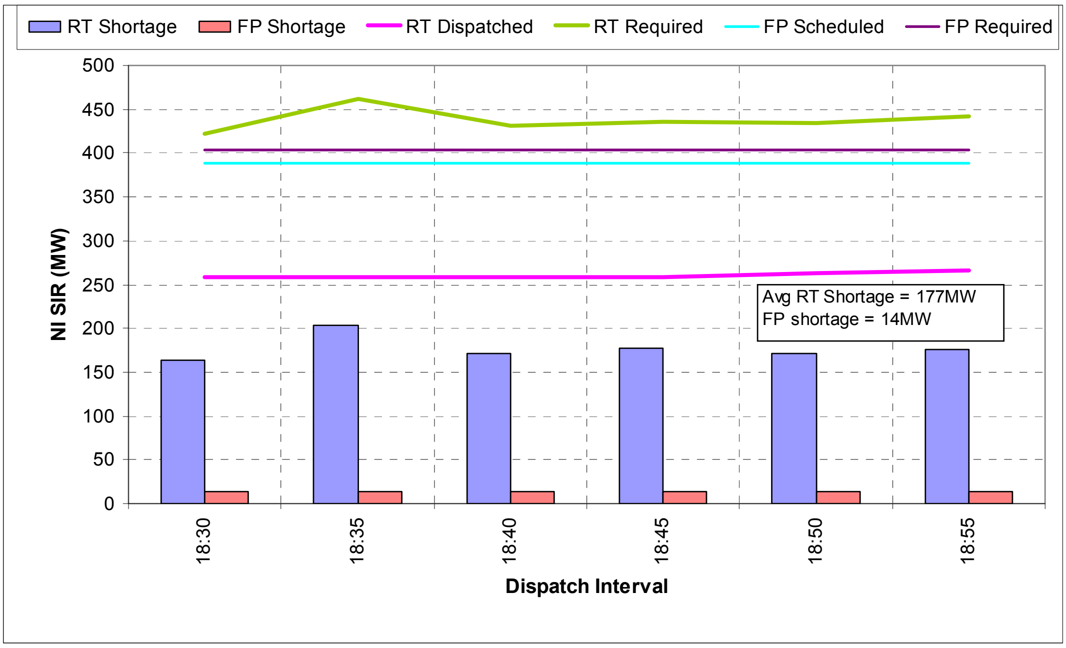


B.12 An average SIR shortage of 177MW would have occurred during real-time dispatch for TP38. During final pricing a 14MW SIR shortage would have occurred. This is illustrated by Figure 7.

99 Allowing for any adjustments within the MCE to account for constraints and other effects.

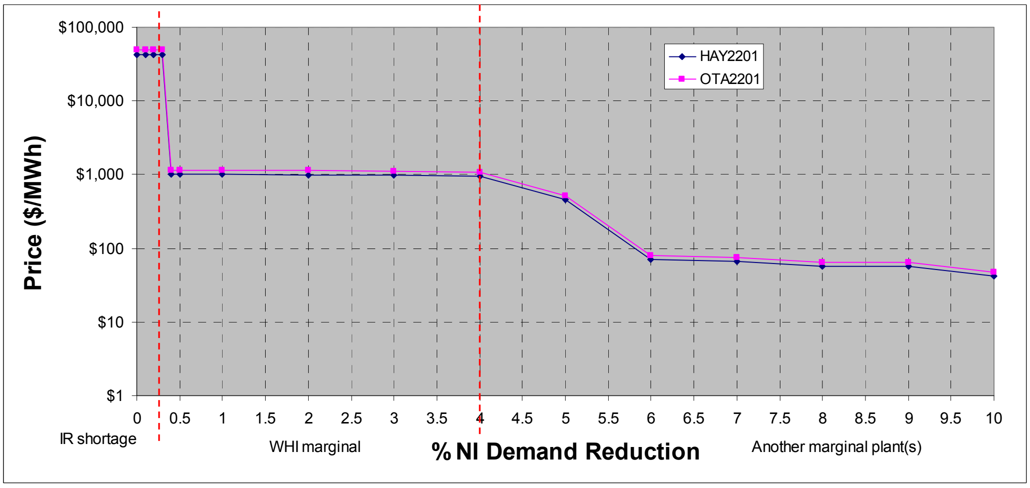
100 Note: The FP Scheduled line is not visible as its value is identical to the FP Required line.

Figure 7: North Island Sustained Instantaneous Reserve (real time and final pricing)



B.13 The sensitivity of the North Island energy prices to variations in actual metered demand (which could arise due to forecast uncertainties or variations in response to curtailment instructions) is shown in Figure 8 (note prices are on a log scale).

Figure 8: North Island energy price sensitivity to demand variation – 5 October 2009



B.14 If the actual load served had resulted in an IR infeasibility in the final pricing process, then the final prices would be subject to the infeasibility resolution process. In this analysis, the net free reserve (NFR) was increased to resolve the infeasibility[101]. The infeasibility resolution process in this case results in North

[101] The NFR is an adjustment (increase or decrease) the System Operator makes to the amount of reserve procured to account for the net outcome of favourable and unfavourable effects on the power system following an event. Favourable effects include such things as uncleared or unoffered reserve capability from partly-

Island prices of over $40,000/MWh due to the system being close to the point of infeasibility[102].

B.15 If the curtailed demand was sufficient to result in no IR infeasibility in final pricing, then settlement prices would have been $1,000/MWh[103], rather than over $40,000/MWh. A demand reduction of between 0.3% and 0.4% (12 MW to 16 MW) would have been sufficient for the IR infeasibility to be resolved. This is a modest amount, considering an *average* SIR shortage of 177 MW would have occurred during dispatch.

B.16 If the demand reduction is increased (beyond 16 MW), there is increased likelihood of the energy prices reducing further. If the demand reduction during real time was in the order of the real time SIR shortage (177 MW) then this would have resulted in a 4.25% reduction in metered demand and resulted in energy prices settling just below the then Whirinaki offer price (between $500/MWh and $1,000/MWh). If 177 MW of demand reduction was requested and the actual response was 5% greater, prices would have reduced by a further $450/MWh to $950/MWh to settle around $50/MWh. This is due to minimal capacity being offered after Whirinaki in this case (there is a fairly rapid drop-off in prices of ~-$12/MWh for each additional MW for a range of around 80MW between 4% and 6%).

4 July 2010 – TP36 (17:30)

B.17 On 4 July 2010, there was no IR shortage experienced during the dispatch process. However, a emergency notice was issued due to the tight energy/IR situation in the North Island with limited HVDC transfer capability (only Pole 1 was in operation during TP36).

B.18 In the final price schedule, Whirinaki was not scheduled and Huntly unit 6 was the marginal North Island generator, with an offer price of $4,950/MWh. Had demand curtailment been implemented (because conditions were thought to be more severe) during the dispatch process, then curtailment of less that 0.5% of load (~20MW) would have maintained the Huntly unit as the marginal supplier in final pricing.

B.19 Had the demand curtailment been greater than 20MW, then the final prices would have reduced quite rapidly, at ~-$85/MWh for each additional MW reduction up to 2% load reduction (~80MW). Thereafter the final prices would have been less than $100/MWh and additional demand reductions would have less of an effect

loaded generating units, and load damping and inertia. Unfavourable effects include possible tripping of non-compliant generators following an event. The calculation of net free reserve, generally, reduces the quantity of instantaneous reserve required to be procured

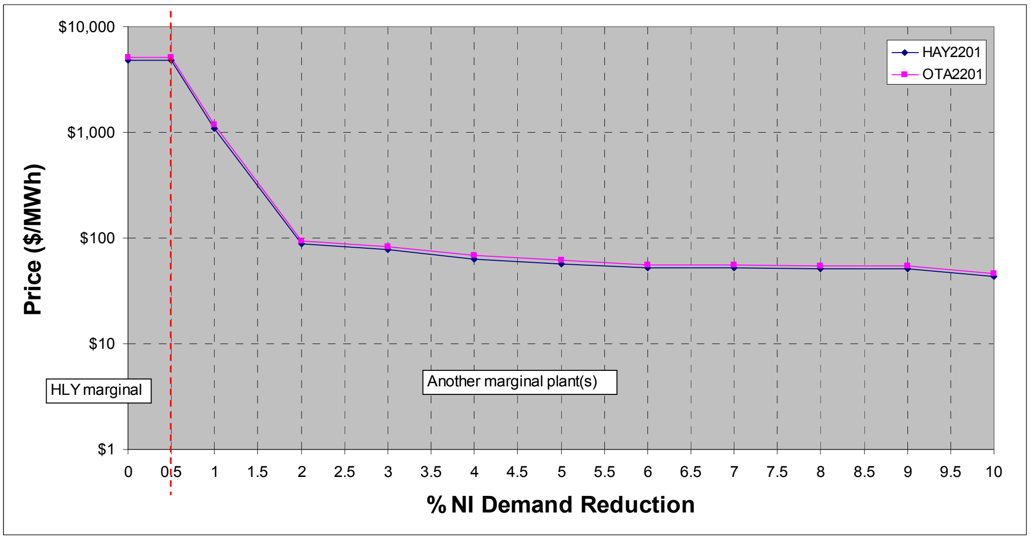
[102] The actual infeasibility resolution process also allows for inclusion of real-time conditions for adjustment of risk adjustment factors (RAFs) and/or net free reserves (NFRs).

[103] Bearing in mind that this was the Whirinaki offer at the time, and was increased to $5,000/MWh from 1 March 2010.

on prices (~$0.15/MWh for each additional MW). These effects are illustrated in Figure 9 (note prices are on a log scale).

B.20 This illustrates the counter-intuitive point that, if the event had been more severe and demand curtailment been implemented, and if the quantum of demand curtailment actually delivered was greater than strictly required, then final prices could have been at levels that would be considered ‘normal’ (approx. $85/MWh in this instance).

Figure 9: North Island energy price sensitivity to demand variation – 4 July 2010



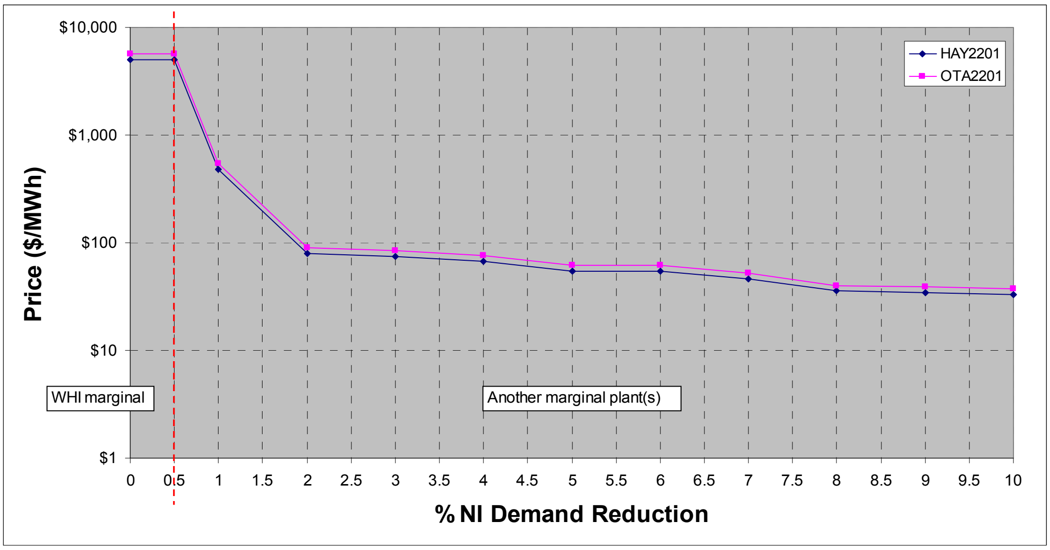
6 September 2010 – TP36 (17:30)

B.21 On this day IR shortages were experienced during the real time dispatch process. The extent of these IR shortages is not known. However, it appears that they were not severe[104]. During final pricing, Whirinaki was the marginal plant with an offer price of $5,000/MWh.

B.22 If some demand reduction had been implemented during the dispatch process to alleviate the IR shortage (had conditions been more severe), then demand reduction of less than 0.5% (20MW) would have maintained Whirinaki as the marginal plant in the NI. If demand had reduced in excess of what was requested, there is a likelihood that final prices would reduce quite rapidly. In this case, after Whirinaki the final prices reduce by ~-$92/MWh for each additional MW of demand curtailment up to 2% curtailment (~80MW). Thereafter the energy price reduces at a slower rate with each additional MW reduction in demand (~$0.16/MWh for each additional MW reduction). These effects are illustrated in Figure 10 (note prices are on a log scale).

[104] Given they occurred only for a few 5 minute dispatch intervals during TP36, no demand reduction was called, and they did not manifest themselves in the final pricing process.

Figure 10: North Island energy price sensitivity to demand variation – 6 September 2010



Further testing of prices in IR shortfalls

B.23 Given the potential sensitivity of price outcomes in the actual IR shortfall on 5 October 2009[105], further analysis of simulated IR shortfalls was undertaken.

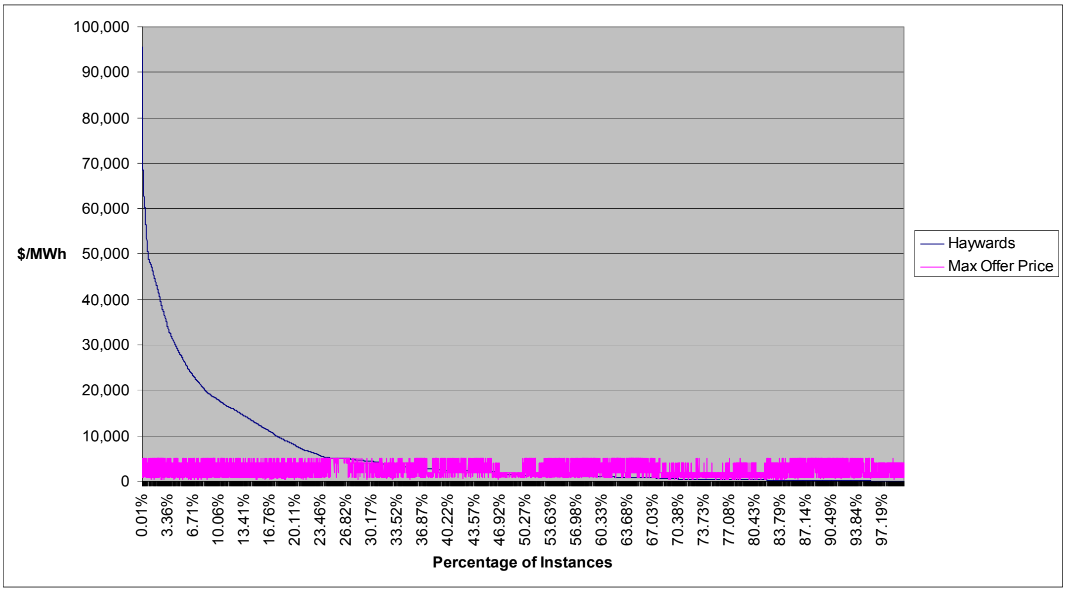
B.24 This was done by using final pricing data for all trading periods in 2008. For each of these periods, the reserve requirement was increased to a point where it almost triggered infeasibility in the final price solution. The resulting price outcomes are shown in Figure 11.

B.25 The chart indicates that under the simulated IR shortfall conditions:

- spot prices would have exceeded the maximum offer ($5,000/MWh) for around 25% of time;
- spot prices would have exceeded $15,000/MWh (3x the highest offer) for around 10% of time.

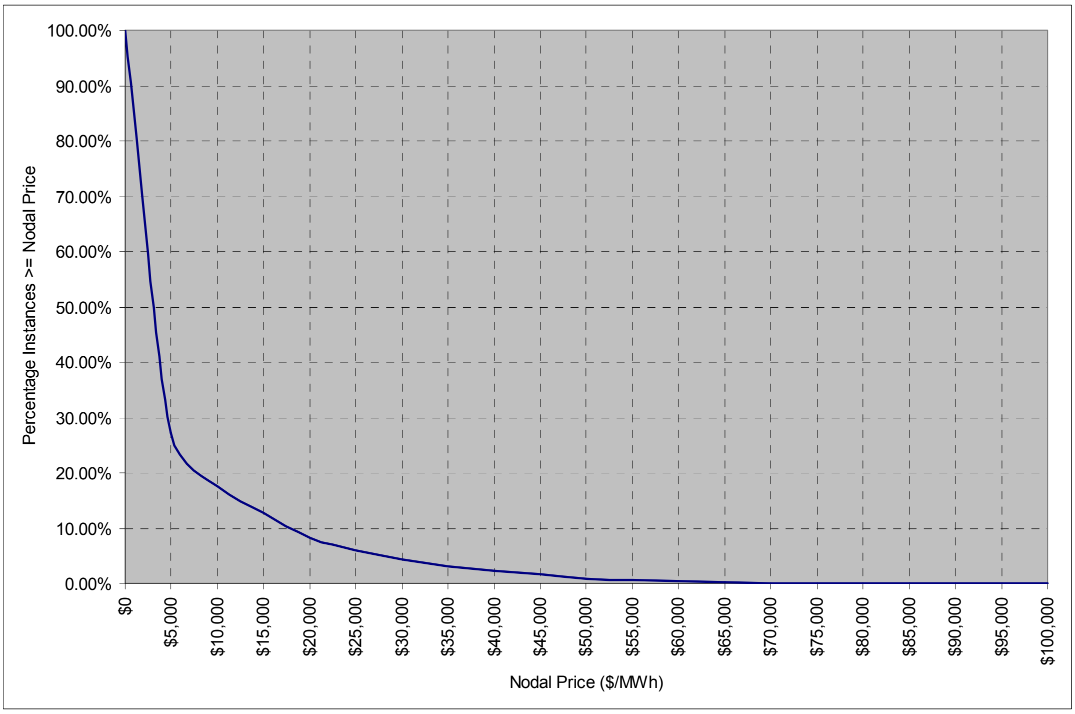
[105] Noting that the recently revised arrangements for pricing in IR shortfalls had not come into effect at that date.

Figure 11: HAY2201 price in simulated IR shortages and highest offer (2008)



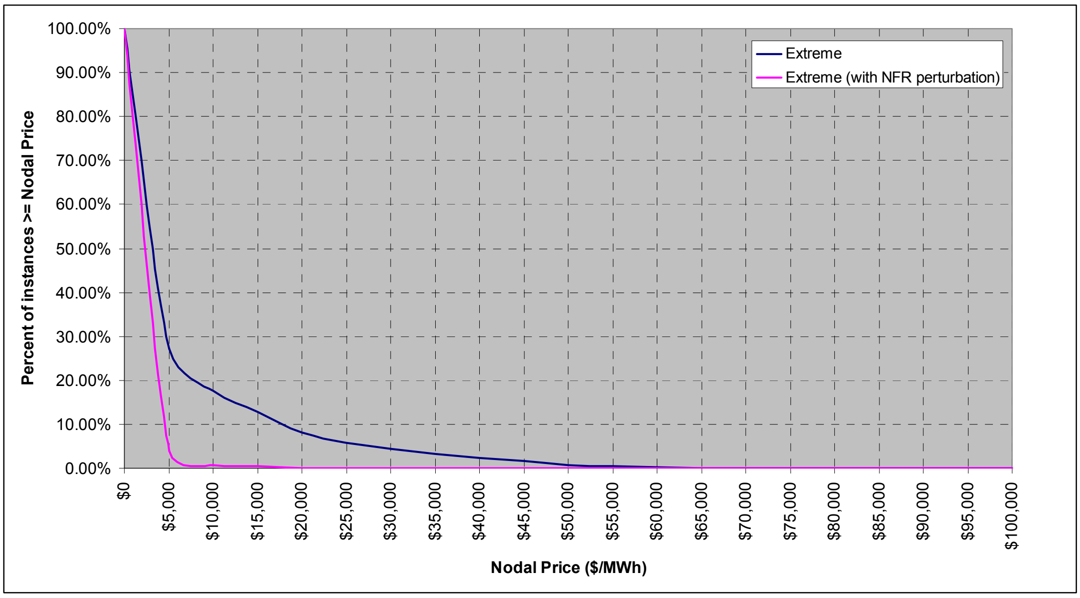
B.26 The same price data from the simulated IR shortfalls is shown as a cumulative probability distribution in Figure 12. It indicates that spot prices would have been $30,000/MWh or higher in 5% of outcomes under the simulated conditions. These prices would have been six times or more above the highest offer price.

Figure 12: HAY2201 price in simulated IR shortage (2008) – cumulative distribution



B.27 A further simulation was carried out to test the sensitivity of these price outcomes if a small variation is made to final pricing input data. In this case, the variation was a relaxation of 0.5MW of net free reserve. The effect of this change to the cumulative price distribution function is shown in Figure 13.

Figure 13: HAY2201 price in simulated IR shortage (0.5MW change in NFR - 2008)



B.28 The analysis indicates that results can be very sensitive to small variations in input data, with a 0.5MW change in net free reserve altering outcomes by over $25,000/MWh in some cases.

B.29 This highlights an issue with current arrangements, which is that price outcomes could be unstable in cases where the final price solution is close to the limit of feasibility. While it could be argued that the price determined by the model is mathematically valid, the sensitivity to small changes in input data is likely to undermine their legitimacy.

Appendix C Incentives on participants from public conservation campaigns

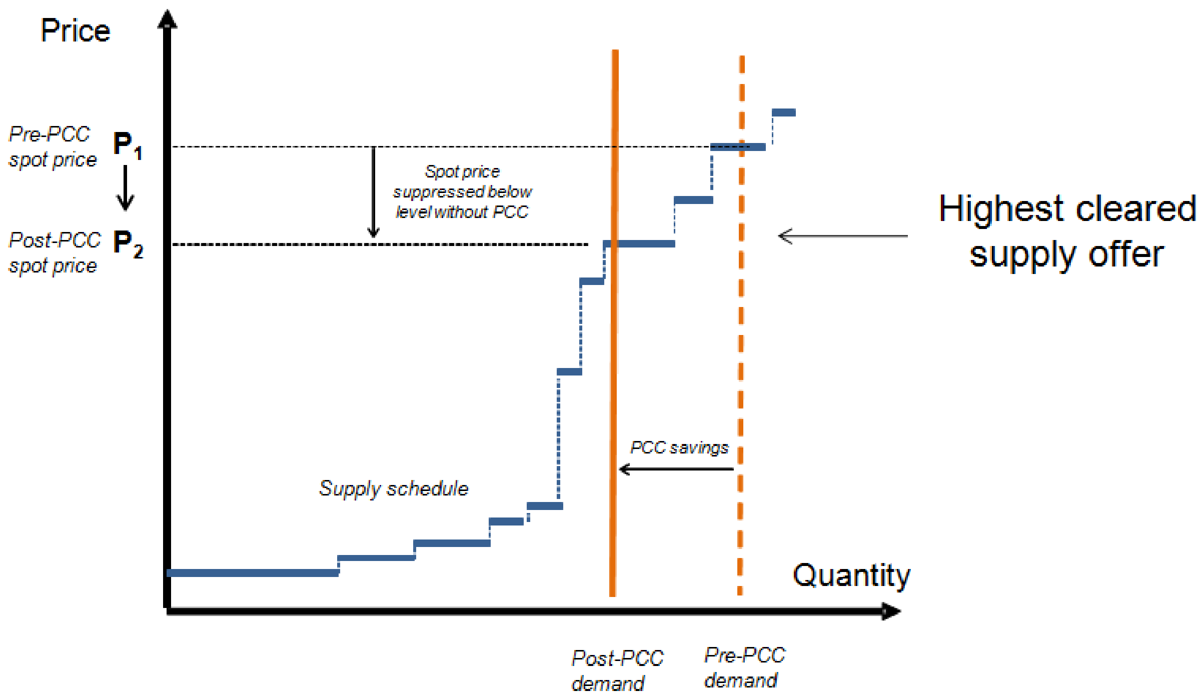
C.1 This appendix discusses the incentives on long-on-load participants[106] to call for public conservation campaigns (PCCs). It also explains why the recently enacted customer compensation mechanism will reduce but not fully address these incentives.

Existing arrangements

C.2 Under existing arrangements, some market participants can have a financial incentive to 'talk up' the risk of a hydro shortage to persuade the media, policy makers and consumers of the need for a PCC. This lobbying fosters a perception that New Zealand is unduly vulnerable to supply crises. This acts to undermine business confidence in New Zealand and increases the likelihood of ad-hoc policy change.

C.3 One aspect of the incentive stems from the fact that the demand reduction from customer savings in a PCC will likely result in prices being lower than they would otherwise have been as illustrated in Figure 14.

Figure 14: Illustration of effect of public conservation campaign on spot prices



[106] Such long-on-load participants could be:

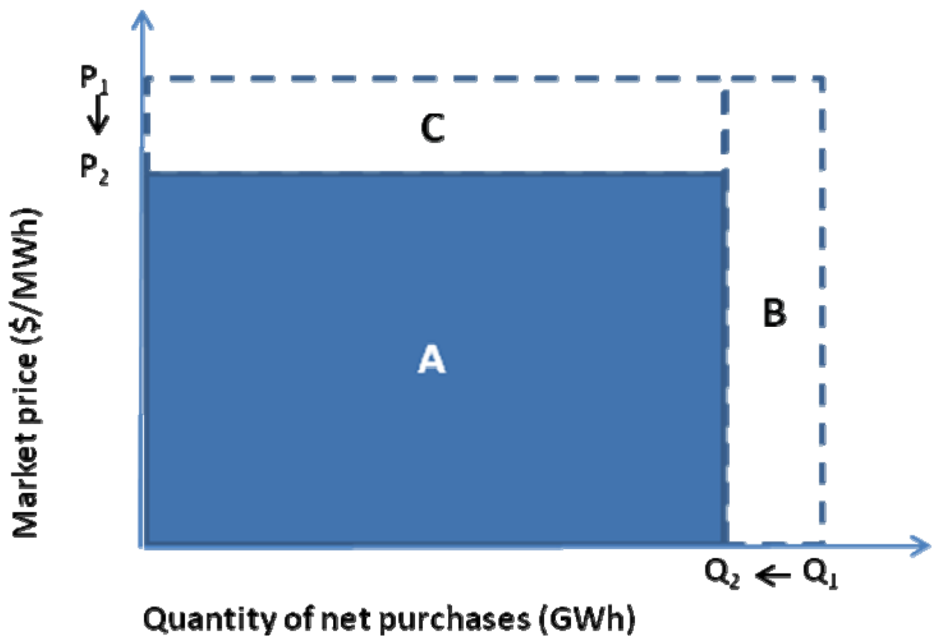
- Under-hedged purchasers (retailers or large industrials); or
- Generators who have 'oversold' hedges beyond their generation capability.

C.4 Any such price reduction will provide long-on-load participants some *price relief* on wholesale purchases.

C.5 In addition, retailers who are selling to customers on a fixed price variable volume basis, will obtain some *volume relief* (as their end-use customers reduce demand).

C.6 The combined effect of the price and volume relief is illustrated in Figure 15. This shows the impact of a PCC on a long-on-load retailer whose net purchases (i.e. the extent to which their purchases exceed any generation / hedges) are at a level Q_1. The market price immediately before the introduction of the PCC is P_1.

Figure 15: Effect of public conservation campaign on the net purchase costs



C.7 Prior to a PCC being called the retailer's net purchase costs will equal P_1 x Q_1, i.e. the sum of the shaded boxes A + B + C.

C.8 Once the PCC is called, the market price falls to P_2, and the retailer's customers reduce consumption such that the retailer's net purchases are reduced to Q_2.

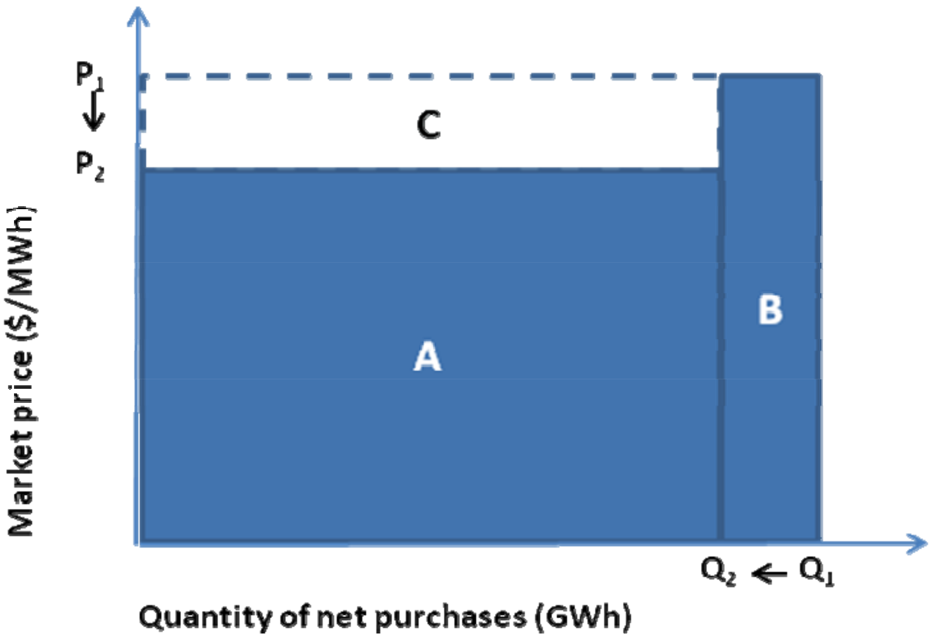
C.9 Thus the retailer's net purchase costs will have reduced to be P_2 x Q_2, i.e. the shaded area A, and it will have saved costs equivalent to the sum of the shaded boxes B and C. These cost savings could be significant for a sizeable retailer (i.e. of the order of millions of dollars a week for a major retailer who is 10% under-hedged).

Effect of customer compensation scheme

C.10 To address the *volume* incentive on retailers, provisions for a customer compensation mechanism have been included in the Code. This mechanism is intended to compensate customers by an amount equivalent to the shaded box B[107].

C.11 However, as shown in Figure 16, a retailer with net spot purchases would still benefit from *price relief* by an amount equivalent to shaded box C. This incentive will not be addressed by the customer compensation scheme.

Figure 16: Effect of a customer compensation mechanism on net purchase costs



Incentives on other wholesale market participants

C.12 The customer compensation scheme affects retailers selling to end-use customers on fixed price variable volume contracts. It does not affect the incentives that other wholesale market participants might have to lobby for public conservation campaigns.

C.13 In particular, generators that are over-sold or wholesale buyers (generally industrial consumers) that are not fully hedged would benefit from a public conservation campaign.

[107] To avoid undue complexity, the scheme is based on pre-estimates of the savings volume and spot price that would be expected in a public conservation campaign.

Appendix D Geographic trigger

Purpose

D.1 This Appendix considers whether scarcity pricing should be triggered for shortages/demand curtailment at any single node, or whether a larger geographic threshold should be required before scarcity pricing is applied to settlement prices. There are four broad options:

(a) scarcity pricing could be applied only where shortage/demand curtailment occurs at the *national* level;

(b) scarcity pricing could be applied only where shortage/demand curtailment occurs in one or both *islands* (with islands being delineated by the HVDC interconnector);

(c) scarcity pricing could be applied only where shortage/demand curtailment occurs at the *regional level*, which would be predefined and be larger than individual nodes, but smaller than whole islands; or

(d) scarcity pricing could be applied where shortage/demand curtailment occurs at any *node.*

D.2 If a minimum threshold is applied, the test would be based on the geographical extent of expected *shortage* when forced load shedding is initiated, rather than where *curtailment* is requested.

D.3 This is because curtailment may not always be requested at every node where savings would be useful. For example, in rolling outages, savings may be useful at all nodes, but the load curtailment instruction is deliberately 'rolled' around the system on a targeted basis. Similarly, during emergency load shedding, there may be instances where load reduction is not instructed at a node for practical reasons (e.g. to preserve a critical user), even though savings would be useful at that node.

Background

D.4 New Zealand's transmission network is relatively 'long and stringy' compared to many other overseas markets, which are more strongly meshed. This gives rise to a strong spatial dimension to ensuring the least cost combination of resources is made available to meet demand for electricity. In particular, transmission losses and constraints can significantly affect the least cost generation resources. In certain instances, there may be insufficient supply into a transmission constrained area, and demand may need to be curtailed.

D.5 To signal the relative value of wholesale electricity at different locations around the grid, New Zealand operates a full nodal pricing model. The model is intended to:

- facilitate efficient *operational* outcomes in terms of achieving the least-cost combination of generation resources to meet demand given the losses and constraints of the grid; and
- facilitate efficient *investment* outcomes in terms of generation location decisions, and investment in demand-side management capabilities by consumers in different locations.

D.6 Given the importance of locational issues, it might seem a logical conclusion that any scarcity pricing regime should provide a scarcity price signal for shortages at individual nodes. However, it is important to consider:

(a) whether scarcity price signals for localised curtailment events are likely to foster efficient investment and operational decisions;

(b) whether alternative approaches may deliver more efficient investment and operational outcomes at the nodal / local level; and

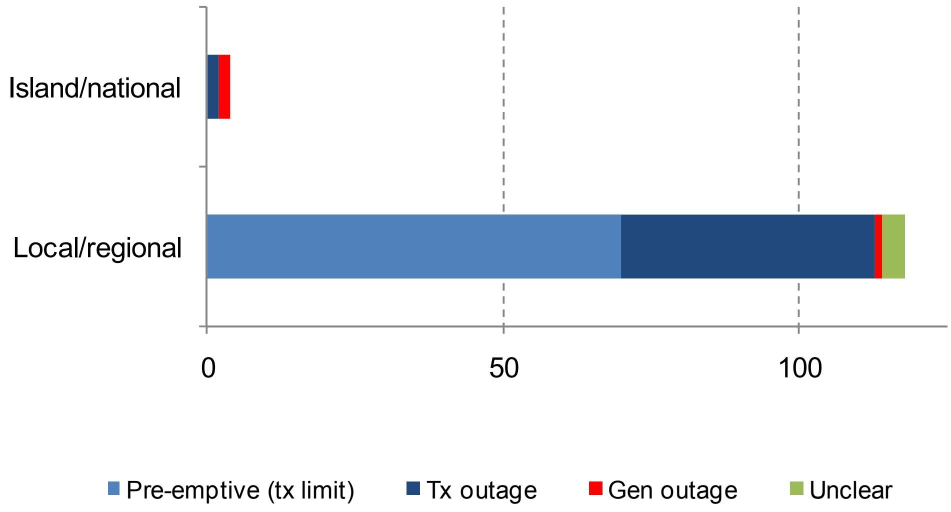
(c) whether nodal scarcity pricing may cause unintended adverse effects, including effects on competition due to increased locational price risk for market participants.

Analysis of historic events

D.7 An analysis was undertaken of 'scarcity' situations[108] between September 2003 and April 2010. Events were categorised into different types, depending on their geographic extent and primary cause. The key results are summarised in Figure 17.

[108] Information was obtained from notices and reports issued by the System Operator. Scarcity events were defined as instances where either: physical curtailment took place due to generation or transmission assets failing while in service; instantaneous reserves had already been reduced or suspended, and demand reduction was "requested" by the System Operator; or a demand reduction was "required" or "instructed" by the System Operator. In some cases, the information is not entirely clear and some judgement has been applied.

Figure 17: Scarcity events by extent and primary cause (2003 – 2010)



D.8 A number of broad observations can be made from the chart:

- local[109] and regional events account for the vast majority of events;
- the great majority of the local and regional events appear to be primarily driven by transmission issues. Only one event appears to have been related to insufficient generation. This was when supply was lost at the Cobb power station on 8 November 2005, necessitating demand management in the Motueka and Motupipi areas for approximately 30 minutes. However, even in this instance, transmission issues may have been important given the limited transmission capacity into the affected area; and
- for island and national events, both generation and transmission issues appear to be important. For the four events identified, two were related to loss of the High Voltage Direct Current (HVDC) inter-island link, and the other two to the sudden loss of generation plant

D.9 Table 7 shows the frequency of events and average wholesale price outcomes that prevailed for a range of representative locations, differentiating such events according to whether they were local, regional, island or national.

[109] Which refers to events that affect one node, or a few nodes in a broader region.

Table 7: Historic price outcomes during past scarcity events[110]

Sample of representative locations	Local		Regional		Island		National		Overall	
	#TPs	Avg price ($/MWh)	#TPs	Avg price ($/MWh)	#TPs	Avg price ($/MWh)	#TPs	Avg price ($/MWh)	#TPs	Avg price ($/MWh)
Kaikohe	0		22	80	53	620	5	2,804	80	608
Auckland	15	66	22	73	53	568	5	2,478	95	475
Hamilton	5	128	27	64	53	540	5	2,368	90	476
Tauranga	100	86	8	32	53	529	5	2,320	166	292
Gisborne	0		3	40	53	515	5	2,380	61	644
Stratford	0		0		53	525	5	2,203	58	670
Bunnythorpe	0		0		53	522	5	2,222	58	668
Wellington	35	80	0		53	522	5	2,185	93	445
Benmore	0		0		0		5	1,834	5	1,834
Christchurch	3	36	0		0		5	2,047	8	1,293
Blenheim	22	92	138	250	0		5	2,249	165	289
Nelson	8	152	138	139	0		5	2,102	151	205
Greymouth	14	198	90	94	0		5	2,161	109	202
Dunedin	0		0		0		5	1,798	5	1,798
Tiwai	0		0		0		5	1,845	5	1,845

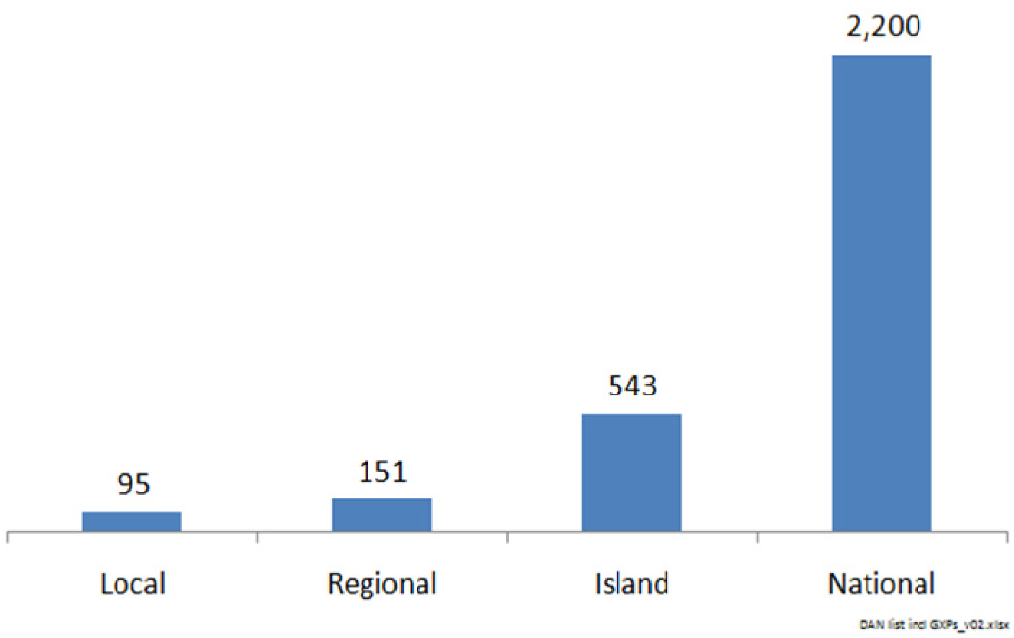
Source: CDS data, System Operator notices

D.10 The frequency of events varied across the grid, for example Tauranga, Blenheim and Greymouth were subject to more local and regional scarcity situations than some other areas. The spot price outcomes also varied significantly according to whether the event was local, regional, island or national. This is illustrated in Figure 18.

D.11 In most of the local and regional events, prices did not reach high levels – in most cases they were no higher than adjacent nodes and were at a level that would not be considered especially high (i.e. <$100/MWh). This may reflect the incentives of the local price setting generator, or the way the pricing mechanism worked in such situations. In either case, it could be argued that prices weren't reflecting the situation of scarcity.

110 "#TPs" = Number of trading periods. Note that some events affected multiple trading periods. The table includes most but not all of the scarcity events listed in Figure 17.

Figure 18: Average $/MWh wholesale price outcomes during scarcity event



Source: CDS data

D.12 If a scarcity price had been applied at any node where scarcity events occurred, it is likely that average spot prices at some nodes would have been significantly higher, *absent any other changes*. This is illustrated in Table 8 which shows the increase in average prices over the period from September 2003 to April 2010, if a scarcity price of $10,000/MWh had been applied during the identified scarcity events.

Table 8: Increase in average prices if nodal scarcity price applied[111]

Sample of representative locations	Original price ($/MWh)	Num of scarcity TPs	Avg price increase ($/MWh)
Kaikohe	72	80	6.5
Auckland	68	95	7.8
Hamilton	66	90	7.4
Tauranga	68	166	13.9
Gisborne	70	61	4.9
Stratford	65	58	4.7
Bunnythorpe	67	58	4.7
Wellington	68	93	7.7
Benmore	65	5	0.4
Christchurch	70	8	0.6
Blenheim	75	165	13.9
Nelson	72	151	12.8
Greymouth	76	109	9.2
Dunedin	76	5	0.4
Tiwai	66	5	0.4

Source: CDS data

D.13 The effect on average spot prices varies widely, ranging between $0.4/MWh (e.g. for Dunedin) to almost $14/MWh (e.g. for Tauranga or Blenheim) at a scarcity price of $10,000/MWh. It is important to re-emphasise that these increases assume that no change occurs in response to scarcity prices, such as greater investment in and use of voluntary demand response or local generation.

D.14 The intention of scarcity pricing is to provide incentives for participants to undertake actions that have a lower cost than curtailment, where these are feasible. The potential for such economic efficiency improvements is discussed in the next section.

Economic efficiency impacts

Effect on incentives

D.15 Had scarcity prices been applied (or been expected to apply) at the nodal level for the historic events detailed above, it is possible that different outcomes may

[111] And no other change occurred. As discussed elsewhere, a behavioural response would be expected, such as greater voluntary demand response, or different generation patterns, or investment in peaking capacity.

have resulted in terms of investment in, and operation of, demand side response and local generation.

D.16 For example, it is understood that retailers in the East Cape have sought demand side response and embedded generation options in response to high prices at times of constraint in that region. Similarly, in response to scarcity pricing signals in distribution prices on Orion New Zealand Ltd's distribution network, consumers have responded with a range of embedded generation and demand side response initiatives. This appears to largely explain why the rate of peak MW demand growth in the Christchurch region has been significantly lower than other areas of New Zealand.

D.17 Further, while current technology limits the ability of most consumers to directly respond to prices, the advent of advanced metering and 'smart' control could progressively open up opportunities for the demand side to more dynamically interact with the market – potentially facilitated by initiatives such as demand-side bidding and dispatchable demand. In this respect, it is possible there may be a 'chicken and egg' dynamic, with such outcomes being less likely to emerge unless there are strong price signals driving market participants to explore such options.

D.18 However, it is not clear that increased demand side response and local generation would have been the most economic option to resolve all or even most of these historic situations of localised or regionalised scarcity.

D.19 In some cases, transmission-related initiatives may have been a more cost-effective way of addressing such scarcity, including:

- investment in upgraded capacity into a region
- altered maintenance approaches, such as:
  - altering timing of outages and/or increased live-line working[112]
  - other maintenance-type investments[113]
  - stricter enforcement of no under-build requirements[114]

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[112] It should be noted that no specific evaluation has been undertaken as to whether Transpower could have altered the timing of maintenance outages, or done more live-line working, to deliver better outcomes. In the absence of such an evaluation, it is therefore possible that little or no improvements could have been achieved.

[113] For example, some years ago the Timaru area was suffering an above expected frequency of outages caused by double circuit back-flashovers from lightning strikes. The affected lines were lightly loaded. The cause was high tower footing resistance. The cure was to put counterpoise conductor underground between towers and to bond at every tower. The conductor was scrap overhead line conductor that had been de-commissioned at end of life. The application of nodal scarcity pricing would not have facilitated this solution, as Transpower is not exposed to spot prices. Instead, it is possible that local generation or DSM solutions would have been promoted, even though they were more costly than the transmission modification.

[114] Two recent, significant and well-publicised outages related to incidents occurring underneath transmission lines (a forklift truck, and a fire, respectively) which would not have occurred if the area under such lines had been 'operated' as Transpower had requested.

- altered grid configurations (either during 'normal' operation, or during maintenance periods), including:
  - physical configuration changes; and
  - modelled changes in pricing and dispatch engines. For example, more refined line ratings through dynamic line rating initiatives.

D.20 In respect of transmission investment decisions, these are proposed by the transmission provider, and approved (or not) by the Commerce Commission[115]. Neither party is directly exposed to spot prices. Instead, the regulatory test is intended to take account of the expected cost of non-supply when assessing the benefit of potential transmission investment[116].

D.21 Furthermore, transmission investments often have longer lead times than generation or demand-side alternatives. This means they may need to be evaluated and committed several years before a transmission constraint actually bites and gives rise to high prices at a node. As a result, where there is uncertainty about the likelihood of generation or demand side alternatives, there can be a tendency for transmission investments to proceed to relieve an anticipated constraint, which in turn removes the need for local demand side response or generation.

D.22 Arrangements for 'transmission alternatives' are (in part) intended to address this issue. It is possible that a process for identifying and procuring transmission alternatives may be a more practical and efficient means of delivering such local generation and demand side response, than solely relying on scarcity pricing signals, especially for risks that are transient or difficult to predict (e.g. risks associated with line outages due to maintenance or upgrades on other parts of the grid).

D.23 With respect to altered transmission operation (i.e. maintenance, and grid configuration), scarcity pricing would also not have any *direct* impact on Transpower as the Grid Owner or System Operator because it is not directly exposed to such prices. Some overseas jurisdictions have incentivised the Grid Owner and/or System Operator through linking some part of their revenue to wholesale market outcomes with respect to transmission losses and/or constraints. However, such a regime does not currently operate in New Zealand, nor is it likely to be implemented in the near term.

D.24 It is possible that nodal scarcity pricing may have some *indirect* impact on the Grid Owner and/or System Operator decisions, in that parties affected by high prices may agitate for Transpower to improve the situation. However, it is not clear that this is the most efficient or effective means of incentivising altered transmission operations or investment.

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[115] This role was previously undertaken by the Electricity Commission, and from 1 November 2010 the responsibility transferred to the Commerce Commission.

[116] Transmission investments can also take place where a customer and Transpower enter into a New Investment Contract. These are not subject to approval by a regulatory body.

Risk management considerations

D.25 Another factor to consider is the effect of the geographical boundary on locational price risk for market participants.

Past market outcomes

D.26 Analysis suggests that locational price risk has been a material consideration affecting retailers' choice of where to compete for customers in the past. Figure 19 presents information on where the five main generator-retailers have retail load[117], and the relative locational price risk they face in different regions[118]. The chart includes data up to July 2010.

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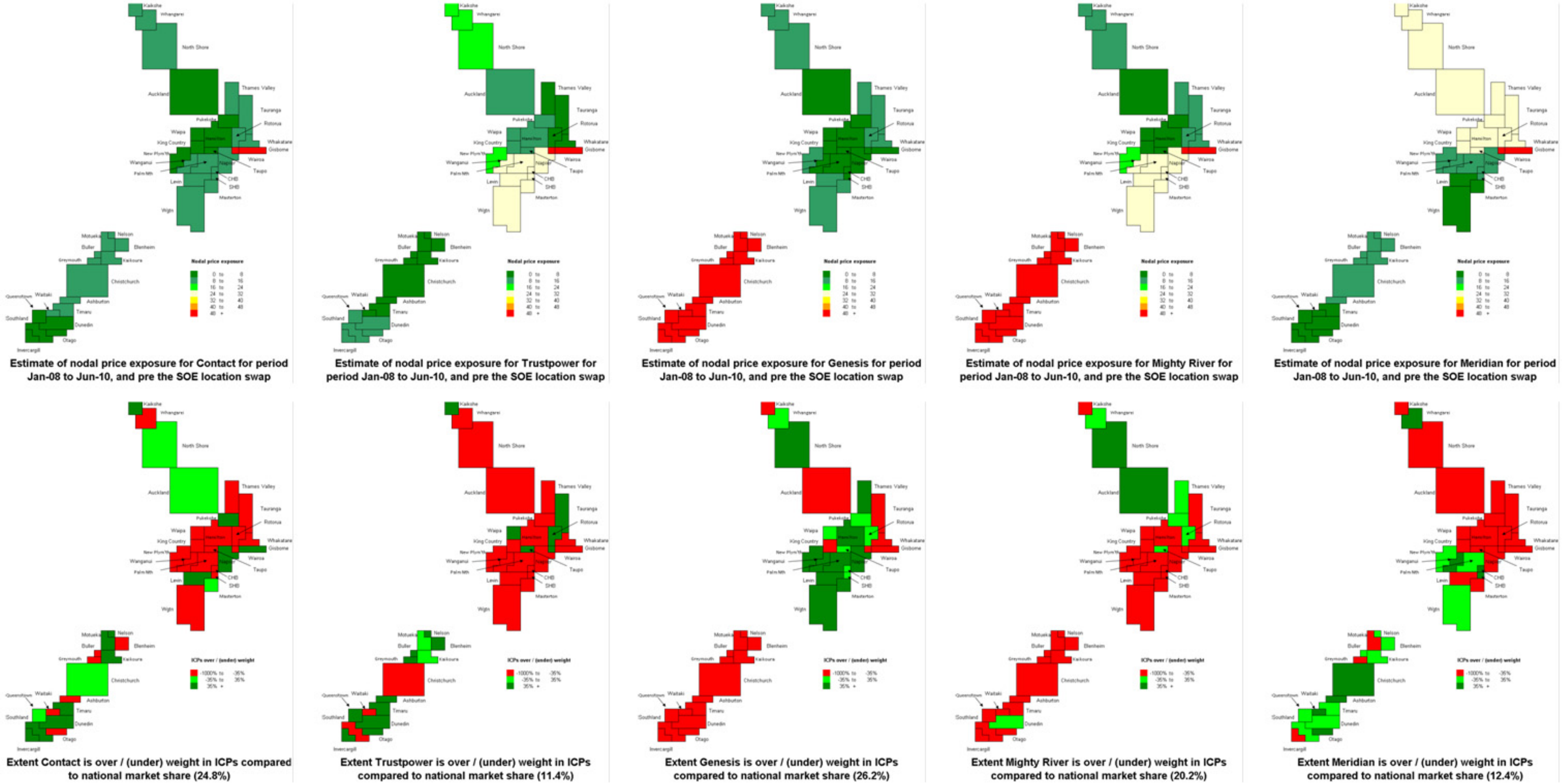
[117] This is measured by the extent to which each supplier is 'over-weight', 'on-weight' or 'under-weight' in a particular network area compared to its national average market share. Being 'on-weight' was assumed to be if market share in a network was +/- 35 percent of its national average. For example, if a retailer had a national market share of 20 percent, it would be deemed to be under-weight in a network area if its market share in that area was less than 13 percent (i.e. 20% * (1-35%)), and over-weight if its market share of that area was greater than 27 percent (i.e. 20% * (1+35%)).

[118] This is measured by looking at the historical variability (as measured by the standard deviation in half-hourly prices) between spot prices in each network supply area, and prices at the nearest (electrically speaking) point at which the company has significant generation resources. In the case of Meridian, Haywards has been treated as a generation supply point because it receives a large proportion of the HVDC loss and constraint rentals.

Figure 19: Maps of geographical locational price risk and mass-market retail presence for the five main generator-retailers



Estimate of nodal price exposure for Contact for period Jan-08 to Jun-10, and pre the SOE location swap

Estimate of nodal price exposure for Trustpower for period Jan-08 to Jun-10, and pre the SOE location swap

Estimate of nodal price exposure for Genesis for period Jan-08 to Jun-10, and pre the SOE location swap

Estimate of nodal price exposure for Mighty River for period Jan-08 to Jun-10, and pre the SOE location swap

Estimate of nodal price exposure for Meridian for period Jan-08 to Jun-10, and pre the SOE location swap

Extent Contact is over / (under) weight in ICPs compared to national market share (24.8%)

Extent Trustpower is over / (under) weight in ICPs compared to national market share (11.4%)

Extent Genesis is over / (under) weight in ICPs compared to national market share (26.2%)

Extent Mighty River is over / (under) weight in ICPs compared to national market share (20.2%)

Extent Meridian is over / (under) weight in ICPs compared to national market share (12.4%)

D.27 There appears to be a strong correlation between where generator-retailers have lower locational price risk, and where they have sought retail load. The instances where a retailer is ‘over-weight’ in more risky area are almost always where the retailer acquired an incumbency at the time of the original lines-retail split in the late 1990s.

Locational price risk implications

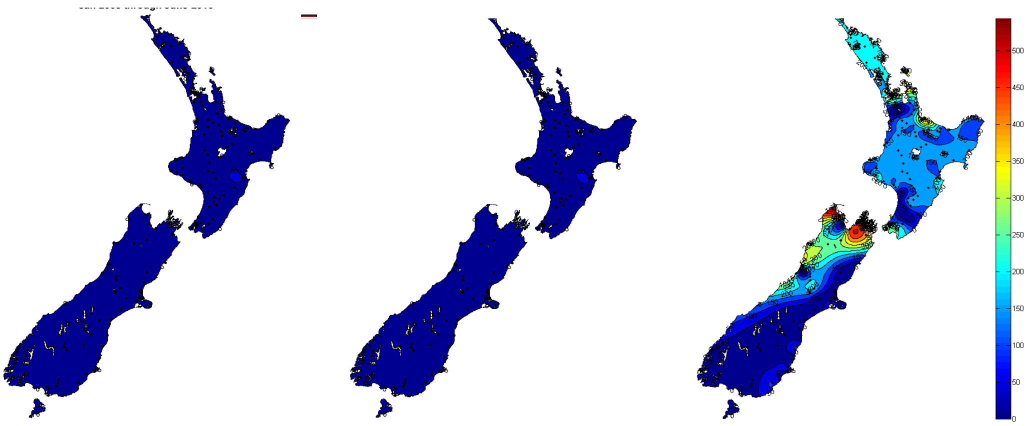
D.28 Analysis has been undertaken to assess the potential effect on locational price risk of applying scarcity pricing for single node shortages.

D.29 Figure 20shows the results of this analysis. It depicts the standard deviation of differences between half hourly spot prices for different nodes and an island reference price (Benmore for the South Island and Otahuhu for the North Island). To the extent that prices at the local node are correlated with the reference node, this will result in a lower standard deviation and vice versa.

D.30 The left hand map shows actual data for the period January 2005 to June 2010. The standard deviations across all of New Zealand ranged up to approximately $100/MWh. The middle map shows the estimated effect if scarcity pricing had been applied for island level events or greater (based on methodology described above). This shows no change from the status quo – i.e. the differences between nodal prices and island reference prices are similar, if scarcity pricing is applied at the *island* level.

D.31 The right hand map shows the estimated effect if scarcity pricing had been applied for all events, i.e. if scarcity pricing is applied at the *nodal* level.

Figure 20: Standard deviation of nodal price relative to island reference price



Status quo Island level threshold Nodal level threshold

D.32 While the methodology can only provide indicative results (since no behavioural response is assumed), it does suggest that nodal scarcity pricing would be likely to appreciably increase *intra*-island locational price risk for some locations. The standard deviation of price differences to the island reference point increases by a factor of five or more in some cases.

D.33 Looking forward, it is possible that some areas which have historically been subject to transmission constraints may no longer suffer such issues due to transmission or generation investment. However, it is equally possible that other areas may start to become subject to transmission constraints due to load growth or changed generation patterns.

D.34 Irrespective of the specific pattern of constraints in the future, it appears likely that the application of scarcity pricing at the nodal level could materially increase intra-island locational price risk relative to the status quo, whereas application at the island level would not be expected to have a material impact. Given that locational price risk already appears to negatively impact on competition in some areas, it would be undesirable to increase this risk further, unless participants have tools to adequately manage it.

D.35 In this context, the introduction of Financial Transmission Rights (FTRs) between the two islands has been proposed. This should significantly improve the ability of a participant with generation/hedge in one island to manage purchasing risk in the other island. However, the current proposal will not introduce any new mechanisms to *intra*-island locational price risk (though this issue remains under investigation for future action).

D.36 In principle, this could be addressed by modifying the proposed locational price risk arrangements. However, even if wider measures were adopted to include intra-island risk, the net effect on locational price risk would depend on the precise design, and participants would be likely to require some time to become familiar with new tools. In the meantime, there would be a potential for the actual or perceived increase in locational price risk to impede competition.

Sustainability and durability of geographic boundary

D.37 Another consideration is the sustainability and durability of an appropriate geographic boundary over time.

D.38 As indicated above, if scarcity pricing had applied for all shortages down to single nodes, some parts of the grid, particularly at the periphery, are likely to have experienced significantly higher prices at times. As well as potentially negatively impacting on retail competition, such outcomes could have material cost implications for consumers in affected areas.

D.39 The emergence of larger price differences for consumers who are geographically close together will naturally raise questions from stakeholders. While differences may (at least theoretically) reflect the relative marginal value of electricity at each node, it is important that such effects can be readily explained and justified.

D.40 In this context, the extent to which the price signal can encourage more efficient investment and operating decisions will be important. Where the scope for efficient response by demand-side or generation providers is very limited (and transmission providers are not directly exposed to prices), this is likely to reduce the sustainability of the chosen geographic boundary. The predictability of the boundary is also likely to be important. For radial parts of the grid, a relatively stable boundary could be drawn. For the meshed part of the grid, there is potential for loop flow effects, making it difficult to define any stable boundary. This issue could arise with the application of regional boundaries, but would not arise with national, or island based thresholds.

Broad options for alternative geographic threshold

D.41 This section sets out the broad geographical options for application of scarcity pricing.

National option

D.42 If scarcity pricing was limited to national curtailment events, the concerns noted earlier regarding the potential to create perverse price signals and increase locational price risk would not arise. However, it is likely that a different problem would emerge - namely that it wouldn't be applied to situations where nodal price signals would be useful.

D.43 For example, limiting application to nationwide shortages would mean that scarcity prices would not be triggered if shortage and load shedding occurred throughout one island. This would likely be too restrictive, since there are events below the national level that the wholesale market could be expected to manage, such as an extended drought or loss of a major station in one island.

Island option

D.44 Taking these considerations into account, there appears to be a case to apply scarcity pricing at least on an island-wide basis. This would mean that if the North or South Island experienced a shortage event that triggered widespread[119] demand curtailment only in one island, prices in the affected island would reflect scarcity values (subject to any applicable cap mechanisms), and prices in the other island would not be directly affected.

D.45 With the proposed introduction of FTRs between the two islands, market participants will have improved ability to manage any increased *inter*-island locational price risk emerging from such an approach.

D.46 Price differentials between islands should also be explainable, given that different physical conditions can apply in either island.

Sub-island regional option

D.47 It is possible that the island definition could be extended further to allow for major regions *within* an island. This recognises that there may be areas that are sufficiently distinct in terms of risk to warrant separate identification, but which are large enough to avoid the issues associated with nodal scarcity pricing noted above.

D.48 However, it may prove challenging to develop a robust set of criteria to define such within-island regions, which ensure that only 'appropriate' regional scarcity pricing triggers are captured. Further, any such arrangements would need to recognise that the electrical

[119] As discussed earlier, the key issue is the extent of the shortage rather than where load shedding is instructed. If an island based threshold is used, it may be administratively easier to define the trigger by reference to instantaneous reserve (IR) cover, since IR is procured on an island basis.

boundaries of regions defined by transmission constraints can change dynamically over time due to a variety of factors such as hydrology, demand changes within the year and from year-to-year, and generation & transmission investment (and retirement) and outages.

D.49 In particular, 'meshed' areas of the grid will prove challenging to define into regions because of potential for loops. If the boundaries of such regions were to be determined dynamically based on the underlying situation, this is unlikely to provide sufficient predictability for stakeholders to make appropriate decisions. Accordingly, it would appear that a sub-island regional approach would need to define distinct regions ahead of time.

D.50 Truly radial spurs on the periphery of the grid are not subject to loop flow issues and could be precisely defined. However, such areas tend to cover relatively small load pockets, and it is likely that a significant proportion of the causes of such regional scarcity would be the transmission-related incidents for which it may be inappropriate to apply scarcity pricing.

D.51 Even if it were possible to reliably define sub-island regions, it is not clear that scarcity prices would improve economic efficiency (i.e. engender actions by generation or demand side response providers, which are on average lower cost than changes to transmission investment or operating decisions). Nor is it clear that such regional definitions could be readily explained and justified, raising questions about the sustainability of this approach.

D.52 Lastly, as noted above, it is likely that the introduction of such *intra*-island regions could increase locational price risk in certain parts of the grid which participants could find hard to manage.

Nodal option

D.53 Scarcity prices could be applied to shortages at any node, including single nodes. This would have many of the characteristics of the sub-island option. In principle, this could create strong incentives for supply and demand-side response down to individual nodes. However, for the reasons discussed above, it is questionable whether such incentives would improve efficiency. There is also doubt about the likely durability of this option.

Proposed option for initial implementation

D.54 It is likely that scarcity pricing applied during curtailments at single nodes or above would lead to significant increases in average prices and price volatility for some parts of the grid. In some instances, this may provide an appropriate signal and facilitate improved outcomes with respect to investment and operation of local generation and demand side response resources. However, this is likely to be far from universal, because transmission decisions have a major bearing on the level of curtailment at the local level, and yet transmission decision-makers are not directly exposed to spot prices.

D.55 The adoption of scarcity pricing for curtailment at any node is also likely to significantly increase locational price risk, which participants could find difficult to manage. Analysis of historic data suggests that locational price risk has retarded retail competition in some areas. Adopting scarcity pricing for curtailment at individual nodes risks exacerbating this situation, unless market participants have the tools to manage increased locational price risk.

D.56 In this respect, it is proposed that new tools to manage *inter*-island locational price risk will be introduced. However, there is no proposal to introduce mechanisms to enable management of *intra*-island risk (though the issue remains under review for possible future action). Although the current proposal could be extended, this would be more complex to implement and the net effect on locational price risk would remain unclear until participants developed experience with new tools. In the meantime, there would be a risk of reduced competitive tension in some areas.

D.57 In light of these factors, applying scarcity prices for nodal or regional curtailment events carries a higher risk of unintended outcomes than if scarcity pricing is applied at the national or island level. Another important consideration is the sustainability of any change (i.e. ensuring policy is not over-ridden in an ad-hoc manner). This is important because a change that is perceived as durable is more likely to elicit the desired behavioural and investment responses. For this reason, a progression of more graduated steps is preferred. Adopting a national or island geographic definition as the initial position doesn't preclude extending the definition to regional or nodal at a later stage once:

- participants have gained experience with scarcity pricing at the national / island level;
- experience has been developed with locational price risk mechanisms (assuming these are adopted); and
- evaluation of the related / alternative mechanisms such as transmission pricing and transmission alternatives has been undertaken and any changes have been determined.

D.58 In conclusion, it is proposed that scarcity pricing be implemented initially for shortage events that affect one or both islands. This minimum geographic boundary should be reassessed as part of periodic reviews of scarcity pricing arrangements. The objective would be to narrow this threshold over time, provided the Authority is satisfied that change will be consistent with the statutory objective.

Appendix E Derivation of scarcity price values

Purpose

E.1 This appendix sets out the approach that has been used to derive scarcity price values for application during emergency load shedding and in rolling outages. It describes:

- the methodologies available;
- the approach to deriving a scarcity value for emergency load curtailment; and
- the approach to determining a scarcity value for rolling outages.

Possible methodologies

E.2 There are two broad approaches for determining the values of scarcity prices to be applied in load curtailment situations:

- set spot prices in curtailment events to a value of lost load (VoLL) calculated to reflect the assessed economic cost of curtailment to consumers (direct estimates); or
- set spot prices in curtailment events to be consistent with achieving a target level of security (security based values).

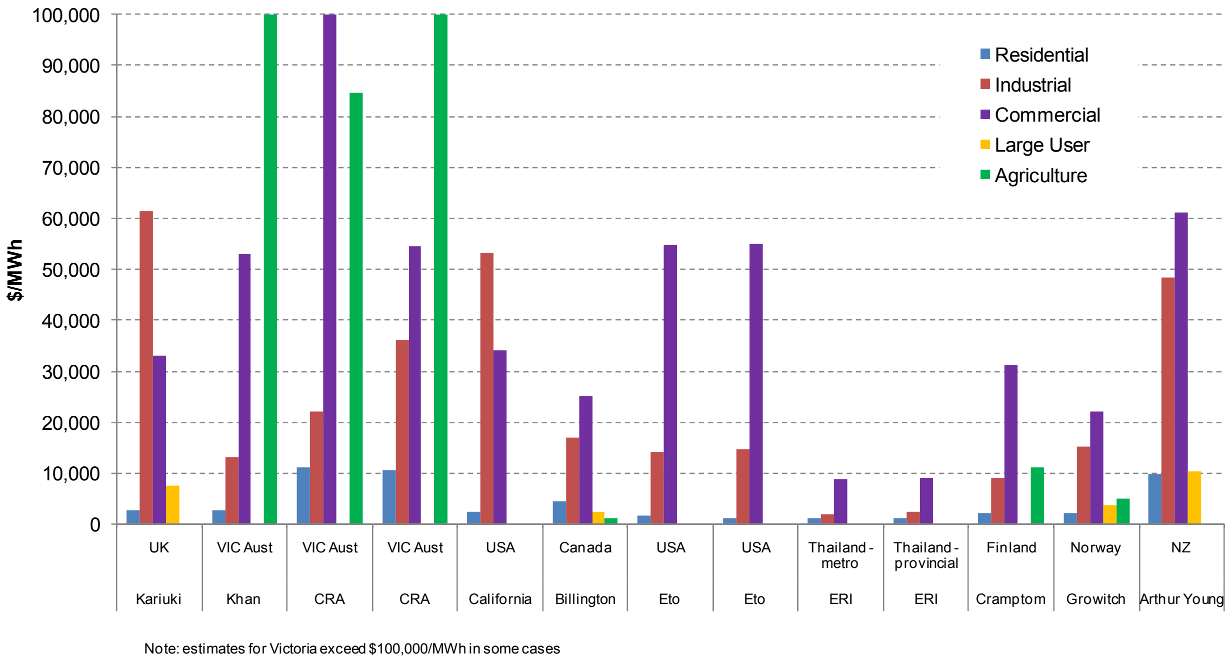
E.3 In theory, the first approach is ideal because spot prices are set to the ‘true’ cost of curtailment. As a result, the mix of supply and non-supply should reflect society’s overall preferences. While this approach has theoretical attraction, there are two key challenges from a practical perspective.

E.4 First, it relies on being able to accurately estimate the value of lost load. In reality, the costs arising from curtailment events will vary, depending on factors such as the type of customers affected, event duration, and the time of day and year when they occur. This makes it difficult to represent the cost with a single value.

E.5 Furthermore, even if every curtailment event were exactly the same in character, it would still be difficult to estimate the cost. This is because the actual costs to consumers cannot be directly observed, and must be estimated on an indirect basis. For example, cost information may be gathered via interviews or surveys of users about the expected costs for hypothetical events, or by inference from users’ willingness to take actions to mitigate the effect of curtailments.

E.6 An indication of the level of estimation uncertainty is shown by comparing the results of international studies into the value of lost load. Figure 21 shows a summary of the results from a range of countries/time periods. For ease of comparison, the results have been converted to New Zealand dollars at prevailing exchange rates, and then adjusted into current dollars[120].

Figure 21: Estimates of VOLL ($/MWh standardised to current NZ dollars)

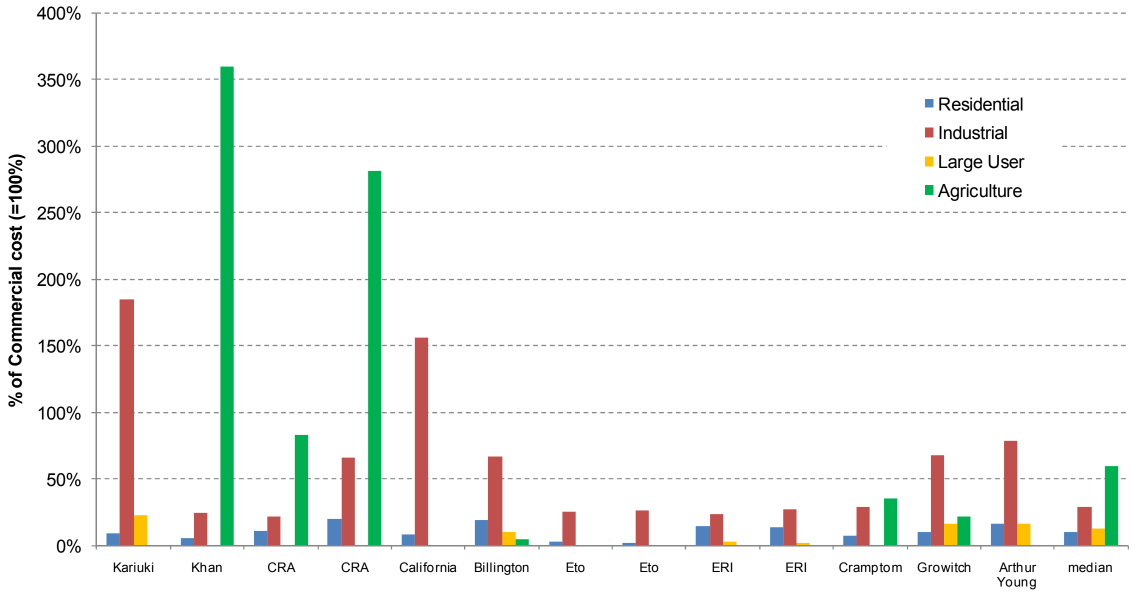


Sources: Various studies. Some source names appears twice because multiple studies were published (e.g. in different years).

E.7 While a degree of variation in VOLL estimates might be expected between countries, the differences are very significant in some cases. There are also large *relative differences* across studies. Figure 22 shows the VOLL estimates for customer types, expressed as a ratio of the VOLL for commercial customers. Again, sizeable variations are apparent between the different countries and studies.

[120] It is important to note that despite these adjustments, the results will not necessarily provide an exact 'apples with apples' comparison as there are variations among the studies in the methodologies that have been applied.

Figure 22: Estimates of VOLL (expressed relative to cost for commercial users)



E.8 Given the uncertainties in estimating the VOLL, it is possible that a pure application of the direct estimate approach could lead to sizeable changes in scarcity price values (up or down) over time. This in turn would tend to increase uncertainty for market participants. In particular, it could increase revenue uncertainty for providers of last resort resource (demand response or generation). This in turn would increase uncertainty about market outcomes.

E.9 Given these issues, the alternative security-based approach has been applied as the primary framework. Where feasible, the results have been cross-checked against the direct estimation method to assess reasonableness.

E.10 The following section describes the use of this security-based approach to derive scarcity prices for situations of *capacity* scarcity. A subsequent section describes the approach to derive scarcity prices for situations of *energy* scarcity.

Scarcity price for emergency load curtailment

E.11 The security-based approach uses a desired security standard as its anchor point. The approach recognises that a 'last resort' resource provider will operate for fewer and fewer hours as the system's security standard increases, all other things being equal. Put another way, if forced load shedding was a frequent event, the last resort resource provider would have greater operating hours than if forced load shedding was extremely rare.

E.12 The expected operating time of the last resort provider is important because fewer hours means that the last resort provider must earn more *per hour* to cover its total costs (i.e. including fixed costs such as fixed operating & maintenance costs, and a return on capital invested). In simple terms, the scarcity price is 'back calculated' by looking at the number of hours that the last resort provider will operate, and dividing this into its annual revenue requirement. For example, if the provider had an annualised cost of $100,000/MW per annum, and expected to operate for 5 hours when the system is achieving the given security standard, this would imply a scarcity price of $20,000/MWh[121].

NZ capacity standard

E.13 The standard used as the anchor point is the capacity adequacy standard developed by the Electricity Commission in 2008[122]. That standard is also reflected in clause 7.3 of the Code.

E.14 The standard was developed using an economic framework which sought to identify the 'optimal' level of capacity adequacy that minimises the overall cost of supply (i.e. the sum of the cost of back-up peaking capacity and demand restraint). This is illustrated by Figure 23, which shows how the cost of back-up peaking capacity (pink line) rises as more capacity is added to the system and security increases. Conversely, as security increases the cost of demand curtailment[123] (blue line) falls.

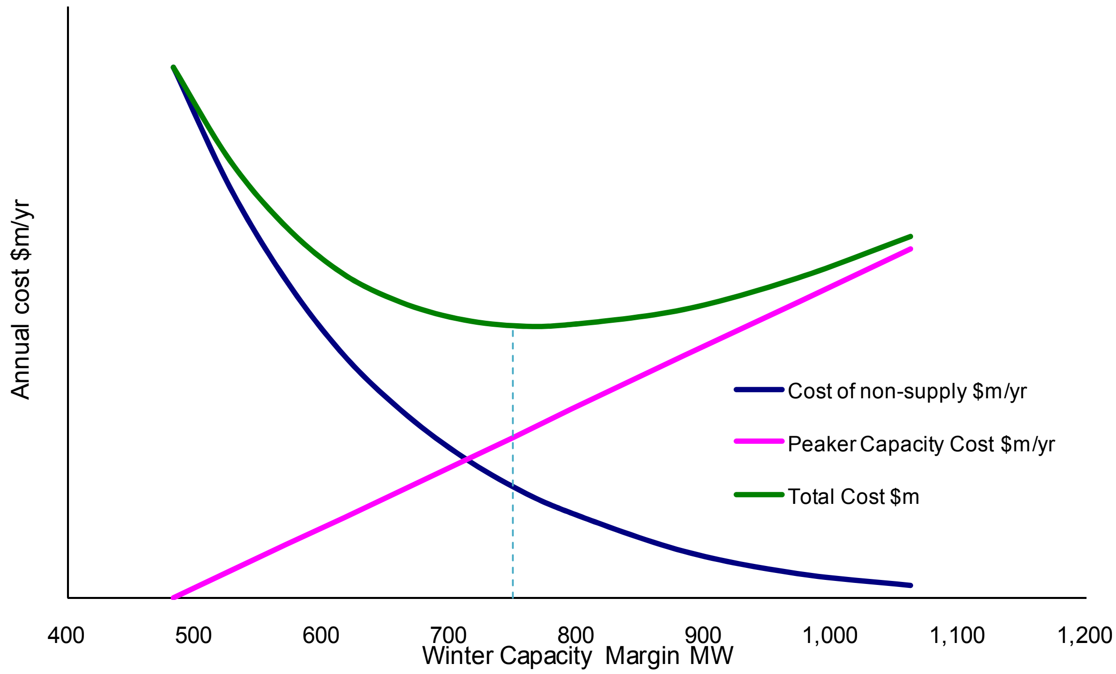
E.15 The overall sum of the two cost components (green line) is shaped like a 'bath tub' and the lowest point (shown by the dotted line) indicates the level of security with the minimum overall cost – in this sense it is the economic optimum. Any movement away from this point indicates that the cost of achieving that level of security exceeds its value to society, or that society is experiencing too much curtailment (relative to the cost of additional supply).

[121] This is a simplified example used for illustrative purposes. It does not take account of the fact that shortfalls can be of differing depths. Nor does it recognise that the plant may earn revenue at times other than an actual shortfall. These issues are discussed later.

[122] See http://www.ea.govt.nz/our-work/consultations/security-of-supply/capacity-adequacy-standard/

[123] This includes both voluntary price based demand response, and involuntary load shedding.

Figure 23: Cost of generation versus cost of non supply



E.16 Additional analysis was undertaken using a chronological simulation model which overlaid historic supply and demand with outage assumptions and provided a framework for examining the impact of chronological issues. Each chronological issue was analysed and a de-rating factor (in MW) was derived to reflect the expected overall effect on MW availability at times of high demand and/or supply contingencies.

E.17 When the analysis was undertaken in 2008, it indicated that a minimum capacity margin of 780MW relative to North Island demand[124] would be optimal[125]. In brief, the analysis employed:

- a modelling approach which recognised that the cost of a capacity shortfall depends on its depth. It involved taking the probability distribution of system loads (the Load Duration Curve incorporating demand uncertainty) and subtracting the probability distribution of supply capacity (accounting for 'de-rating' factors such as plant outages and other factors

[124] More specifically it is a "minimum 780MW margin of de-rated North Island supply over the average of the highest 200 half-hours of winter North Island daytime demands. North Island supply includes the contribution of supply from the South Island accounting for the South Island supply/demand balance and HVDC capability".

[125] The capacity margin formulation was chosen to make it easier to measure and communicate, but does not facilitate international comparisons. A more common measure is the expected level of unserved energy (as a percentage of total unconstrained demand) and the 780MW capacity margin is equivalent to approximately 0.0015% in unserved energy terms. In other words, if total expected North Island demand is 26,000 GWh, average demand curtailment at the optimal standard would be 0.4 GWh (26,000 x 0.0015%). This level is similar to the target reliability standard in the Australian NEM, which is expressed as an expected unserved energy level of 0.002% of demand.

such as wind generation output) to derive a capacity shortfall probability curve (CSC). This identified the probability of exceeding different levels of capacity shortfall;

- assumptions about the annualised cost of new supply (i.e. including both fixed operating and maintenance costs and a return on capital). The lowest cost option for providing back-up at peaks was an open cycle gas turbine (OCGT), with an estimated annualised cost of $124/kW/yr;
- assumptions about the costs associated with differing levels of instantaneous reserve (IR) shortfall and demand restraint[126].

E.18 The same modelling framework has been applied to derive scarcity price values. However, some of the original assumptions are becoming dated. For this reason, the following adjustments have been applied:

- the capacity shortfall curves have been updated to reflect the expected position in 2013 when Pole 3 of the HVDC link is scheduled to become available;
- the estimated annualised cost for an OCGT has been increased to $145/kW and the forward estimate of the short run marginal cost to $350/MWh. This reflects more recent cost information; and
- the IR and demand curtailment cost estimates have been updated for inflation in the period.

E.19 Importantly, while these adjustments affect the cost of supply and cost of non-supply curves, they do not materially alter the estimated optimal capacity standard[127].

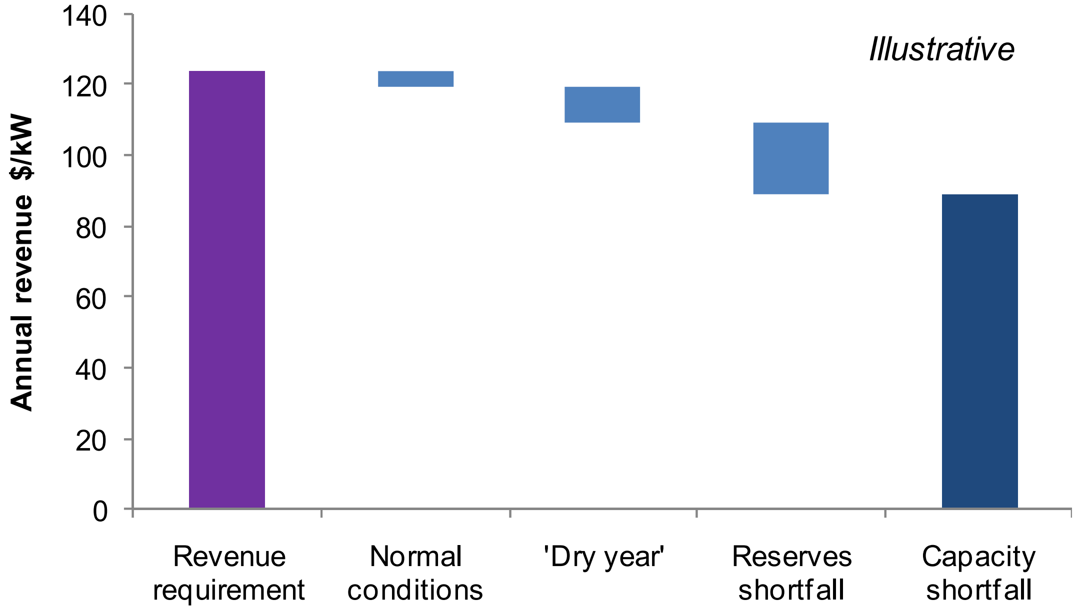
Revenue sources for last resort capacity provider

E.20 As noted earlier, a last resort plant may earn revenues at times other than actual shortage. It is important to consider the extent of these alternative opportunities, because it affects the residual revenue requirement that must be earned during actual shortage, which in turn directly influences scarcity price values. This is illustrated in Figure 24.

[126] For computational ease, the short run marginal cost of the peaking plant (a fixed $/MWh figure) has been deducted from each of the curtailment cost estimates. This allows the cost of supply and the cost of non supply to both be expressed in expected dollars per year for differing capacity margins.

[127] After applying the adjustments above, the estimated optimal standard remained within 1% of the 780MW measure included in the Code.

Figure 24: Sources of revenue for last resort plant (illustrative)



E.21 In the New Zealand context, aside from periods of actual capacity shortage, there are three other *potential* revenue sources:

- normal market conditions;
- energy constraint periods ('dry years') – where the system is not capacity constrained, but spot prices exceed the short run costs of a last resort plant due to energy constraints (likely to be due to low hydro storage and/or thermal fuel constraints); and
- instantaneous reserve shortfall - where the system is run with a higher risk of automatic load shedding or system collapse than is preferred and price induced voluntary demand curtailment is likely

E.22 For the system to maintain the desired level of security, the last resort resource provider must be able to obtain sufficient revenue in total from these sources to cover its costs. The following sections describe the approach that has been used to estimate the overall revenue requirement, and the expected revenue from each source.

Revenue requirement for last resort capacity provider

E.23 For any plausible level of optimal security, a last resort capacity provider will be called into operation very infrequently. For this type of duty, the conventional plant choice is an open cycle combustion turbine running on liquid fuel[128]. This type of plant has fast response times and is reliable. Furthermore, given its low expected level of running hours, the higher variable costs (due to fuel) of this plant type are more than offset by capital cost savings. For

[128] Demand response may also provide 'last resort' coverage, but this is incorporated in the assumptions made about the costs of voluntary and involuntary load shedding.

this analysis, an annualised cost of $145/kW/yr[129] for an open cycle turbine has been adopted.

E.24 Irrespective of the actual *level* of required revenue, it is important to note that a provider could obtain this revenue via direct reliance on spot prices, or (more likely) the sale of hedge contracts to another party or an associated retail business to provide insurance against volatile spot prices. While the form of the revenue stream will differ (i.e. will be very volatile or smoothed over time), in both cases it relies on an *expectation of occasional very high spot prices*.

Revenue during 'normal' market conditions

E.25 This analysis is focussed on the revenue that a last resort plant would *reliably* expect to earn. During periods of 'normal' market conditions (i.e. where sufficient capacity is offered to meet demand and provide instantaneous reserves, and not in a dry period), the mean expectation is that the last resort provider will not be required. For this reason it is unlikely that a prospective provider would factor in any firm revenue contribution from this source.

E.26 This is not the same as saying a last provider will *not* earn any revenue during 'normal' periods. There could well be situations where some revenue is earned, particularly in situations where the system is tight but not experiencing a capacity or IR shortfall[130]. However, it would appear imprudent to treat such revenue as firm.

E.27 For these reasons, this analysis has assumed no spot market revenue is earned by the last resort plant during 'normal' conditions. As a point of comparison, based on examination of published documents, this appears to be consistent with the approach taken in the Australian NEM.

Revenue during energy constraint periods ('dry years')

E.28 An important issue to consider in the New Zealand context is the extent to which a last resort plant will earn revenue in energy constraint periods (commonly referred to as 'dry years' but covering any period when there is sufficient capacity to service current demand but there is a fuel or energy deficit[131] which undermines the ability to serve future demand).

E.29 In these periods, revenue could arise whenever spot prices are above the last resort plant's short run marginal cost – estimated to be around $350/MWh. This would be expected to include periods of price-induced demand restraint, public conservation campaigns, and rolling outages.

E.30 The approach taken to address this issue in New Zealand recognises that the system needs to satisfy both capacity and energy standards to provide adequate security. At any point in

[129] This is based on a capital cost of $1155/kW, a 10.6% capital recovery factor and $15/kW fixed operating & maintenance costs.

[130] Particularly if demand side sources can participate more directly in price setting, which at time could result in prices that clear above the short run marginal costs for generators.

[131] Put another way, where forecast demand exceeds energy production capability.

time, it is likely that only one of the standards will be the binding constraint. Accordingly, if there is sufficient resource[132] in the system to provide adequate capacity, there is likely to be *more than* sufficient to meet the energy requirement, or vice versa[133].

E.31 This observation can then be used to assess which constraint is likely to be the binding one based on the current system characteristics (e.g. demand shape and level, plant mix and characteristics etc). If the system is operating at the binding constraint for either capacity or energy, the amount of surplus capability on the other variable can be used to estimate the revenue available from that source.

E.32 Turning to examine the New Zealand system, the relationship between system capability and the relevant standards is shown by Figure 25. The New Zealand Winter Energy Margin (NZ WEM) is measured on the horizontal axis and the North Island Winter Capacity Margin (WCM) on the vertical axis. The current standards (17% and 780MW respectively) are shown by the solid and dotted red lines. All positions in the upper right quadrant meet both these standards.

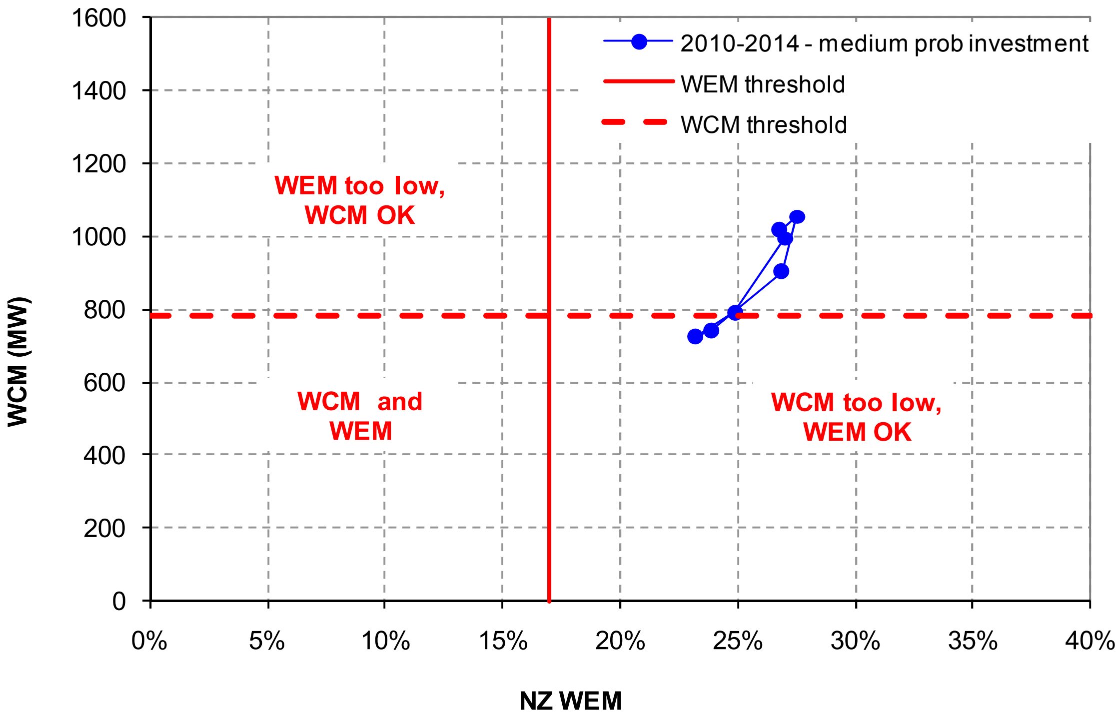
E.33 The blue dots trace the expected position of the system over the 2010 – 2014 period, based on the Annual Security Assessment published by the Electricity Commission in 2009. The position moves from one year to another to reflect expected changes in demand and new investment over this period[134].

[132] Both generation and voluntary demand response providers.

[133] Recall that these standards refer to the amount of resource on the system – i.e. the availability of fuelled generation plant and demand response resource that can be relied upon. Some allowance is made for situation where resource is in existence, but is not available for technical reasons (e.g. plant outages, unit commitment uncertainty etc).

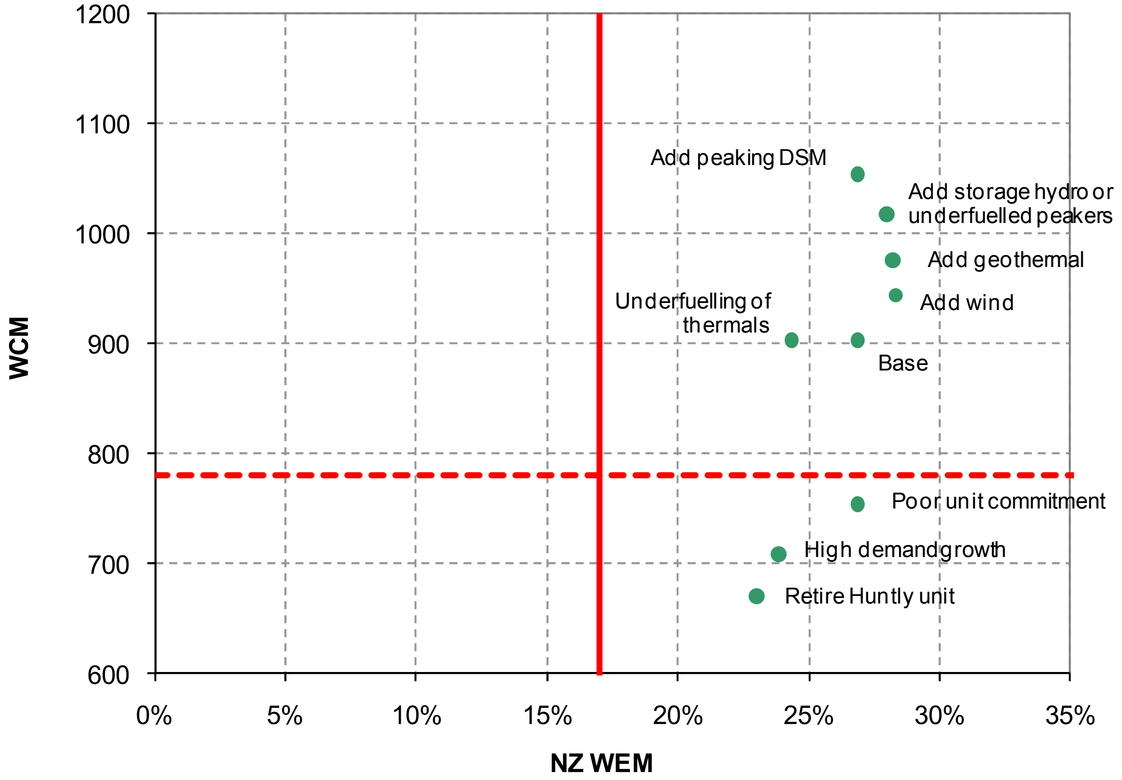
[134] The medium probability case for proposed and committed new investments is shown on this chart.

Figure 25: System capability versus energy and capacity standards



E.34 To calculate these energy and capacity margins, a number of assumptions are made about matters such as demand growth, plant operation, management of thermal fuel stocks and hydro storage. Altering these assumptions affects the system's expected capability in relation to the energy and capacity standards. This is illustrated by Figure 26 which shows a number of alternative scenarios, relative to the 'base' position.

Figure 26: System capability - scenarios



E.35 The key points to note from the two charts are:

- under most scenarios, it appears *likely* that there will be more 'headroom' on the energy standard than the capacity standard; and
- if the system were to be just meeting the capacity standard (780MW), it would imply a New Zealand Winter Energy Margin of approximately 24% (relative to a minimum standard of 17%).

E.36 Based on these observations, it is possible to estimate the amount of revenue that a last resort plant could expect to earn during energy constraint periods if the system were meeting the capacity standard. This is estimated at approximately \$20/kW/year from 'dry year' events[135].

[135] This analysis is based on the approach used to derive the optimal energy standard in 2008. The key assumptions include 2% voluntary savings at around \$300-\$400/MWh, spot prices at \$500-\$2,000/MWh during conservation campaigns and energy restrictions, and \$3,000-\$5,000/MWh during rolling outages. As noted earlier, these assumptions have been updated and differ slightly from those used in 2008.

E.37 It is important to acknowledge there are uncertainties associated with this figure. In particular, as noted earlier, assumptions[136] are required about:

- the operating patterns of hydro and thermal plant during differing levels of energy constraint;
- the extent to which voluntary demand restraint occurs at different price levels;
- the extent to which transmission constraints (or other factors) might affect the ability of resources to simultaneously contribute to meeting energy and capacity requirements[137]; and
- the level of spot prices during differing levels of levels of energy constraint.

E.38 In light of these uncertainties, the effect of varying the revenue earned in energy constraint periods is tested in the sensitivity analysis section discussed later in this paper.

Revenue during instantaneous reserve shortfalls

E.39 In addition to procuring energy to meet forecast demand, the System Operator normally procures sufficient instantaneous reserve to ensure that the single largest contingent event can be covered without involuntary load shedding.

E.40 However, if there is insufficient capacity available and offered to the market, the System Operator can operate the system in an “emergency secure state” with less than normal instantaneous reserve. The system is still secure, in the sense that it is not likely to collapse, but there is an increased risk of automatic load shedding if there is a sudden loss of a large generation unit (e.g. a CCGT unit) or the HVDC whose capacity is greater than the amount of IR in operation. The extent of the risk will depend on the shortfall in instantaneous reserve.

E.41 For example, normally around 400MW of instantaneous reserve is procured at peak times, corresponding to the size of the single largest contingent risk which is typically the CCGT units operating at full capacity at such times. If there is a shortfall of 100MW and only 300MW of reserve is available, then the first of the two automatic under frequency load shedding (AUFLS) blocks[138] is likely to be shed if there is a sudden loss of greater than around 300MW of generation or HVDC transfer.

[136] These largely mirror those used in the Electricity Commission’s regular assessment of energy adequacy, which were published and subject to review by stakeholders. (Responsibility for compiling assessments transferred to Transpower as System Operator from November 2010).

[137] At present the system faces a North Island capacity constraint and a South Island (or potentially national) energy constraint. The analysis implicitly assumes that an additional liquid fuelled open cycle turbine can contribute to meeting both requirements. It is possible that transmission effects might in the short run limit the ability of a South Island open cycle turbine to contribute to North Island capacity and vice versa.

[138] These automatically disconnect one or two 16% blocks of load if a large proportion of supply is suddenly lost. This is to avoid “system collapse” which can occur if the frequency falls so much that generation units become unstable and must be disconnected. In this case the entire North and/or South Island supply system will fail and it may take several hours to restore supply.

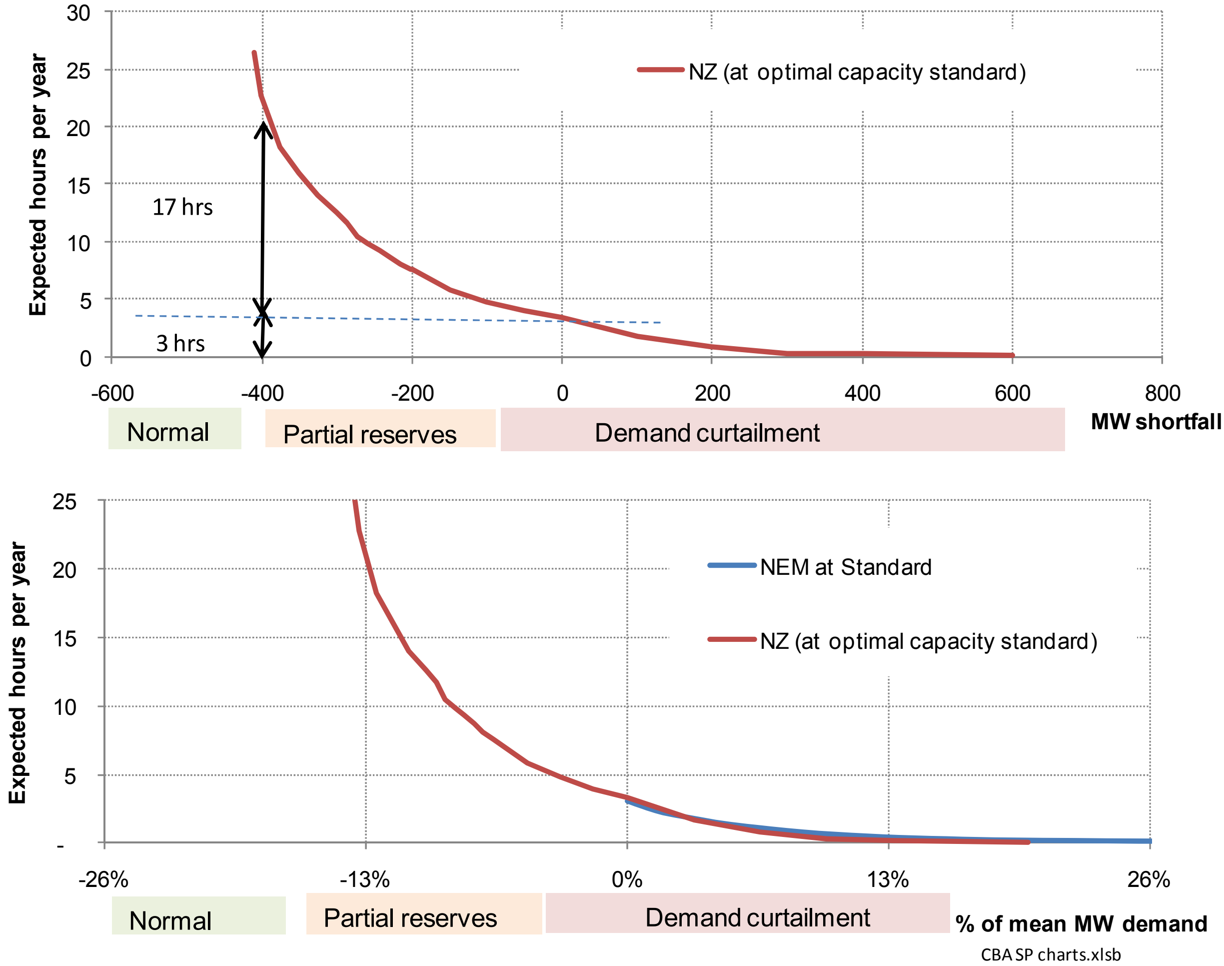
E.42 If the capacity shortfall is 200MW, then a smaller contingency (such as the loss of a 250MW unit) could result in the operation of an AUFLS block. There are twice as many generation units above 200MW as compared to 300MW, and hence the risk of AUFLS events will increase as the capacity shortfall increases. Beyond a certain level of IR shortfall, the System Operator may pre-emptively curtail demand, even if there is sufficient capacity to meet demand. This is because the size of generation or transmission unit failures which would trigger AUFLS becomes so small (and consequentially so much more likely to occur) that it becomes prudent to pre-emptively curtail some demand to prevent the risk of a much larger loss of demand associated with AUFLS.

E.43 Coming back to the issue of scarcity price setting, it is important to consider the revenue earning opportunities for a last resort plant during instantaneous reserve shortfalls. This type of plant is likely to be operating during these events because if the system is under such pressure that there is insufficient supply and interruptible load to cover normal reserves, then *all available* generation will be needed. Given that the last resort plant is designed for fast response, it will almost certainly be in operation.

E.44 Under this reasoning, the frequency of instantaneous reserve shortfall events will have an important bearing on operating hours for a last resort plant.

E.45 The framework used for the capacity adequacy analysis in 2008 can be utilised to estimate the number of hours of capacity shortfall that would be expected, assuming the system is at the optimal capacity standard. The results of this analysis (with the updated assumptions noted above) are shown in Figure 27 (in megawatt terms and as a percentage of system demand to facilitate a comparison with the Australian NEM).

Figure 27: Expected shortfall hours (at optimal capacity standard)



E.46 This indicates that approximately 17 hours of instantaneous reserve shortfall would be expected each year. As the chart shows, for most of these hours the instantaneous reserve shortfall would be expected to be 200MW or less.

E.47 To calculate the revenue that instantaneous reserve shortfalls provide for a last resort plant, it is necessary to estimate the level of spot prices[139] for differing levels of IR shortfall. This is not straightforward because it depends in part on the behaviour of market participants. Furthermore, pricing arrangements for IR shortfalls were changed significantly from mid-2010. Prior to that time, the final pricing process did not fully account for relaxation of IR cover dispatched in real time. This meant that spot prices could be significantly reduced relative to a position where full IR cover was maintained.

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[139] To keep the terminology simple, in this paper "spot prices" means the half hour price for active energy. A separate spot price is calculated for instantaneous reserves products. The analysis implicitly treats capacity as being able to participate in the active energy or instantaneous reserves markets, given that the market clearing engine co-optimises the resources to meet both requirements. As a result, a tight market for an IR product is likely to also accompany a tight energy market, and vice versa.

E.48 From July 2010, the process was altered so that any available IR is dispatched in real time. When final prices are calculated, it is based on the normal IR requirement. To the extent that this creates an infeasible outcome[140], a resolution process is invoked where IR procurement is progressively relaxed in the pricing model until a feasible outcome is reached.

E.49 This is expected to produce a relatively flat price curve for differing levels of IR shortfall, based on the highest offer in the supply curve[141]. That said, as described in more detail in Appendix B, somewhat lower prices are expected for modest shortfalls because:

- where a modest amount of IR cover is relaxed in real time, there is more likelihood that the shortfall will not be apparent when final prices are calculated, because these are based on actual *metered* demand for the entire trading period which has a tendency to be less constrained than the situation experienced during real-time dispatch; and
- the infeasibility resolution process appears likely to produce lower prices for smaller IR shortfalls and vice versa.

E.50 An assumption is also required about the point where the System Operator will institute pre-emptive forced load shedding, rather than further reductions in IR cover. Although this is ultimately decided in real time in light of specific circumstances, it appears unlikely that a situation of nil IR cover would be tolerated, because of the significant risk of triggering Automatic Under-Frequency Load Shedding (AUFLS).

E.51 In that context, the System Operator has recently released a technical report setting out the results of a review of current AUFLS arrangements[142]. The review indicated a degree of concern with certain aspects of existing arrangements, and the System Operator has signalled that it will be proposing some changes in this area[143].

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[140] An infeasible outcome refers to a situation that is technically impossible, in this case having insufficient capacity to meet full reserves cover. Note that even though an IR shortfall may have occurred in real time dispatch (i.e. full reserves were not procured relative to the expected market requirement), there may not be an IR shortfall apparent during the final pricing run. As set out earlier in this document, this can arise for a number of reasons including differences between forecast and actual demand, and variations in plant output or grid capability relative to the expectation at the start of a trading period.

[141] Or a higher value based on these offers if multiplicative effects occur due to particular effects from the mathematical solve of the least-cost dispatch. See Appendix B for more detail.

[142] See System Operator Report: Automatic Under-Frequency Load Shedding (AUFLS) Technical Report, *Transpower,* August 2010

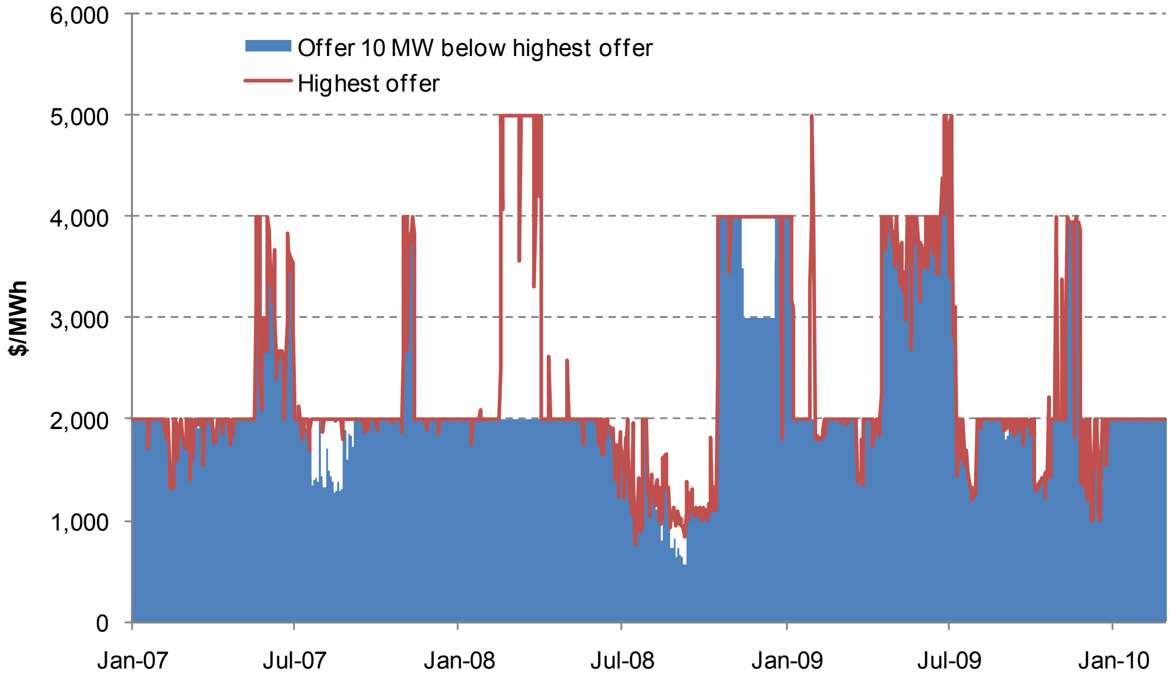
[143] The report stated that "the results show that the System Operator's tools will ensure that there is sufficient reserve generation and demand available to be disconnected to prevent system collapse from large defined risks, such as the sudden disconnection of HVDC bi-pole, at all times. This is likely to require limiting the transfer on the HVDC link to below its maximum capability under certain system conditions to ensure power system security. However, the overall design of the AUFLS scheme provides the System Operator with insufficient confidence that the current AUFLS scheme will be effective to prevent the system from collapsing from large risks that are not currently identified. The studies have also shown that significant over-voltage issues are likely to occur following AUFLS operation which have the potential to collapse the system. The System Operator has identified a number of options to address these issues."

E.52 In the absence of more specific information, the analysis in this paper assumes that a minimum of 150MW[144] of IR cover is maintained, and that forced demand curtailment is initiated if capacity shortfalls of 250MW or more occur.

E.53 These factors can be combined with observed offer prices to derive an expected spot price *profile* for differing levels of IR shortfall in the absence of scarcity pricing (referred to as the counter-factual case). The counter-factual case assumes a value of $3,500/MWh as the highest offer price in the supply stack. This reflects the average of highest offer prices observed in the North Island for the period from January 2007 to February 2010, as shown by Figure 28.

E.54 The chart also shows the generation offer price that was 10MW (about 0.2% of evening demand) below the top of the offer curve for North Island generation. While the offer prices have varied over time, the average has been around $3,500/MWh.

Figure 28: Offer prices for generation



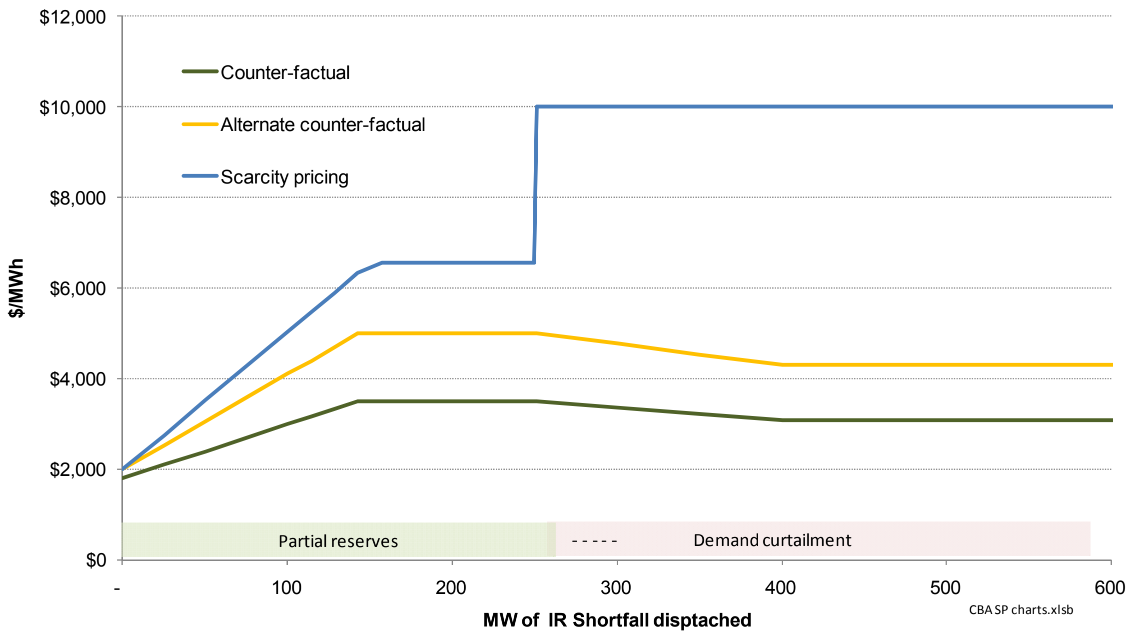
E.55 As noted above, the probability that spot prices will settle on the highest offer price depends on the size of an IR shortfall experienced in dispatch. For this reason, spot prices are assumed to average $2,000/MWh for modest shortfalls, rising to $3,500/MWh on average for IR shortfalls of 150MW or more[145].

[144] This is approximately equal to the quantity of IR provided by interruptible load.

[145] See Appendix B for more detail.

E.56 If demand curtailment is invoked (for larger capacity shortfalls), there is potential for final prices to *fall* due to the tendency for materially more curtailment to occur than is strictly necessary[146]. For this reason, spot prices in actual curtailment situations reflect an assumed 10% weighting of prices equating to those in a modest IR shortfall ($2,000/MWh), and a 90% weighting of prices reflecting the highest offer price ($3,500/MWh). The resulting counter-factual profile is shown in Figure 29.

Figure 29: Spot prices during supply emergencies



E.57 Although it does not affect the derivation of a scarcity price value, Figure 29 also shows an alternate counter-factual with the price profile predicated on $5,000/MWh as the highest offer price. This is based on the Whirinaki offer price which has applied since 1 March 2010. While this case is included for completeness, it is important to recognise that the Whirinaki offer price will become market determined once the Crown's intended sale process for the plant is completed[147]. This case is also used in the cost benefit analysis as a sensitivity case, and for assessing the possible impact of scarcity pricing on wholesale electricity prices.

E.58 Lastly, it is necessary to consider spot price outcomes during IR shortfalls[148] if scarcity pricing is introduced. The values for this represented in Figure 29 are based on an analysis which assumes that spot prices in these situations are higher than under the counter-factual case, but lower than the scarcity price value itself. This reflects a view that some market

[146] See Appendix B for more detail.

[147] In addition, the Electricity Authority is currently consulting on the capacity offer price for Whirinaki and has proposed that it be reduced to the plant's short-run marginal cost, once it is confirmed that sufficient capacity will be available to the System Operator to meet demand.

[148] That is, situations where IR cover is reduced in dispatch, but forced load shedding is not invoked.

participants might alter their offers in light of a scarcity price (as observed in other markets). However, any increase in offer price will reduce the risk of a particular resource being dispatched. This is expected to moderate offer behaviour.

E.59 Once again, it is important to note there are uncertainties around some assumptions. For this reason, sensitivity cases are considered in a later section.

Revenue during emergency load shedding

E.60 The information discussed above has been integrated to estimate the price level required in emergency demand curtailment to provide a last resort plant with sufficient revenue to just cover its costs[149].

E.61 The results of this integration are summarised in Table 9.

Table 9: Estimated scarcity price value

Item	Value
Annualised capital cost ($/kW)	145
Normal market ($/kW)	-
Dry-year ($/kW)	20
IR ($/kW)	107
Demand curtailment ($/kW)	18
Implied Scarcity Price $/MWh	$10,006
	CBA SP charts.xlsb

Scarcity price for emergency load shedding - sensitivity analysis

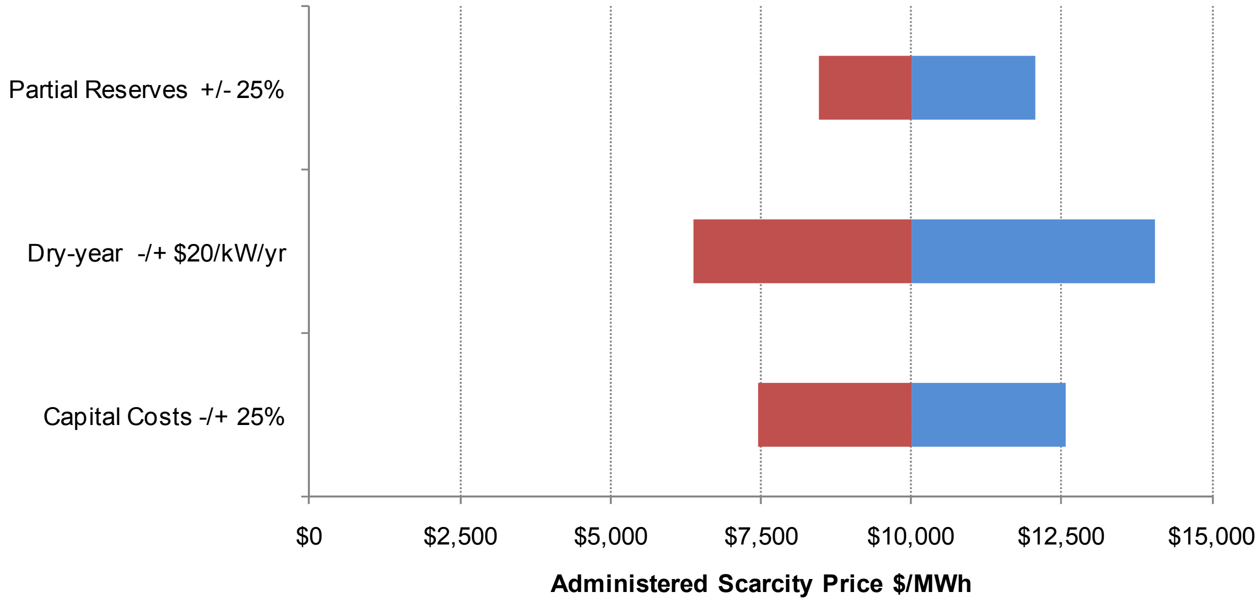
E.62 As noted earlier, the scarcity price estimate is influenced by a number of key input assumptions. Accordingly, the following sensitivity cases have been tested:

- varying the expected revenue earned by a last resort plant during IR shortfall situations. This has been modelled by altering the spot price profile during IR shortfalls by +/- 25%;
- varying the expected revenue earned by a last resort plant in dry years by +/- $20/kW/year (+/-100% of central estimate); and
- varying the capital cost for a last resort plant by +/- 25%.

E.63 The effect of these sensitivity tests is shown in Figure 30. Note that for each variation, the chart shows the result when *all other inputs remain unchanged*.

[149] Note that the scarcity price floor would apply when forced load shedding occurs in dispatch. This load shedding may occur even though some IR cover is maintained. Note also that some allowance could be made for outage risk for the last resort plant. However, this should not have a material effect for OCGT plant which tends to have high reliability.

Figure 30: Effect of varying input values on administered scarcity price value



E.64 Strictly speaking, these results may over-state the sensitivity of the scarcity value to changes in input assumptions, because they ignore some of the potential interactions. For example, if the annualised revenue requirement for a last resort plant was higher than assumed, this would be expected to alter the optimal security standard[150], all other things being equal. This in turn would feed through to affect the required scarcity value.

Emergency load shedding scarcity price – NZ comparative data

E.65 The scarcity price estimate of $10,000/MWh derived from the preceding analysis can be assessed against a number of other comparators. One important benchmark is the estimated value of lost load (VoLL) used for transmission planning purposes. This value is currently[151] set at $20,000/MWh in real terms, with a sensitivity range of $10,000/MWh to $30,000/MWh (all real terms)[152].

E.66 The VoLL used for transmission investment appraisal is higher than the estimated scarcity price value noted above. However, it is not clear that the estimates should necessarily coincide because there may be differences in the nature of generation and transmission related curtailment events, and their consequent costs.

[150] In economic terms, a higher cost of supply would mean that a slightly greater volume of curtailment would be optimal, and vice versa. This assumes that the standard is reviewed from time to time. For the purposes of clarity, this does not appear to occur in the Australian NEM where the standard of 0.002% unserved energy is not determined from an economic analysis (at least not formally).

[151] The Authority is currently undertaking a review of VoLL.

[152] A nominal value of lost load of $23,185/MWh was used by the Electricity Commission in 2009. This is the December 2004 value of $20,000/MWh prescribed in the former Electricity Governance Rules inflated for 5 years. See http://www.ea.govt.nz/document/11391/download/industry/ec-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/

E.67 This issue has been highlighted in overseas jurisdictions with scarcity pricing. For example, the value of customer reliability used in Victoria for transmission planning purposes is currently A$47,850/MWh (2007 A$), compared with a scarcity price of A$12,500/MWh applicable in the wholesale electricity market.

E.68 The Australian Energy Market Commission has noted this difference, and commented that:

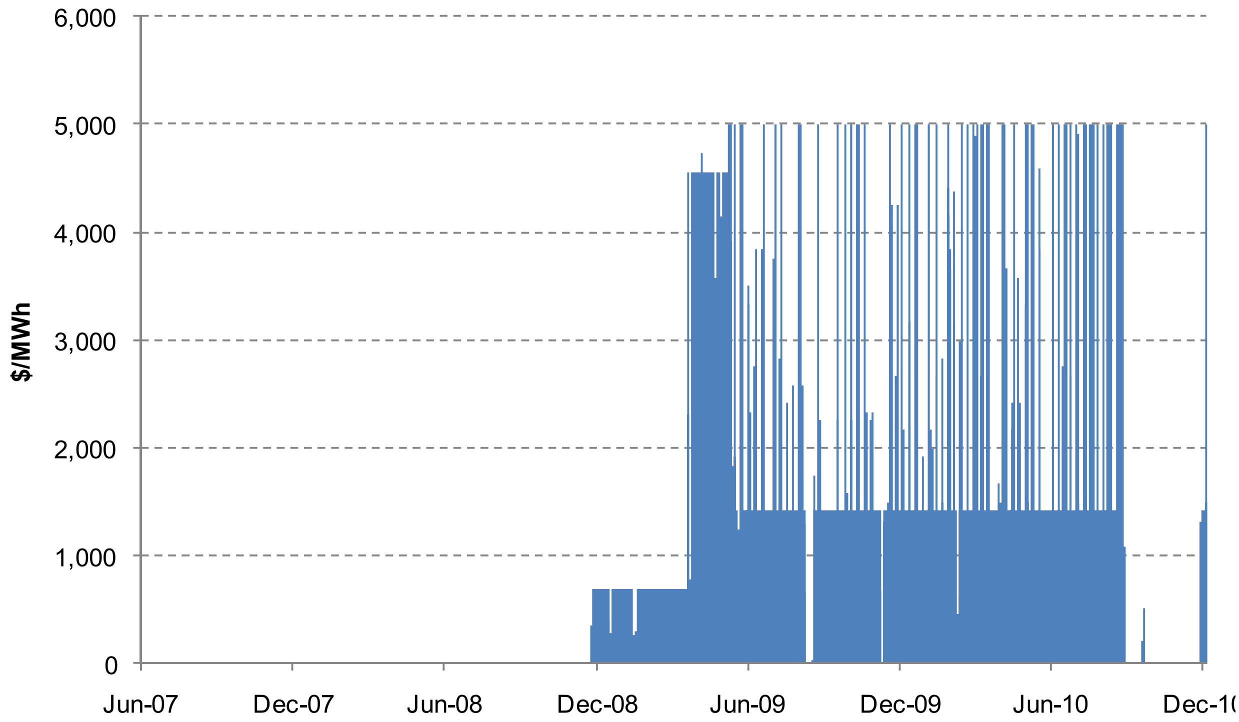
> *"we conclude that efficient investment in reliability across the supply chain can be achieved by investing to the level of Value of Customer Reliability (VCR) for those consumers most affected by the investment. We recommend that for generation investment the VCR level for residential consumers should be used because this class of consumer places the lowest value on reliability and are usually shed first during a reliability event. At present the VCR level for residential consumers (which has currently only been explicitly estimated for Victorian consumers) is estimated to be $13 250/MWh* [compared to $47,850/MWh as the weighted average across all sectors]*, which aligns reasonably close to the MPC* [market price cap/scarcity value] *of $12 500 that will apply from 1 July 2010"*[153].

E.69 Another point of comparison is information on the price at which consumers are prepared to exercise voluntary demand restraint. One such indicator is the offer price for interruptible load in the fast instantaneous reserve market. Figure 31 shows the offer price for the most expensive tranche of this product through time. There has been considerable variation in these prices. However, in more recent times these have varied between around $1,500/MWh and $5,000/MWh.

E.70 Given that interruptible load represents *voluntary* load reduction, it would be expected to have an offer price below the cost of *involuntary* load shedding.

[153] See Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events, *AEMC*, May 2010.

Figure 31: Highest interruptible load offer price (North Island fast instantaneous reserve)



E.71 Another indicator is price information from the Demand-side Participation Pilot trialled by Transpower as a potential alternative to transmission investment in the Upper South Island. Transpower called for tenders for demand-side response (in some cases this involved use of stand-by generation) in the Upper South Island. Transpower received offers for 50MW of demand-side response, which equated to approximately 5% of the load in the area. The offers had prices in the range $700 to $12,000/MWh as shown in Figure 32[154].

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

Figure 32: Price offered per MW per hour for demand response

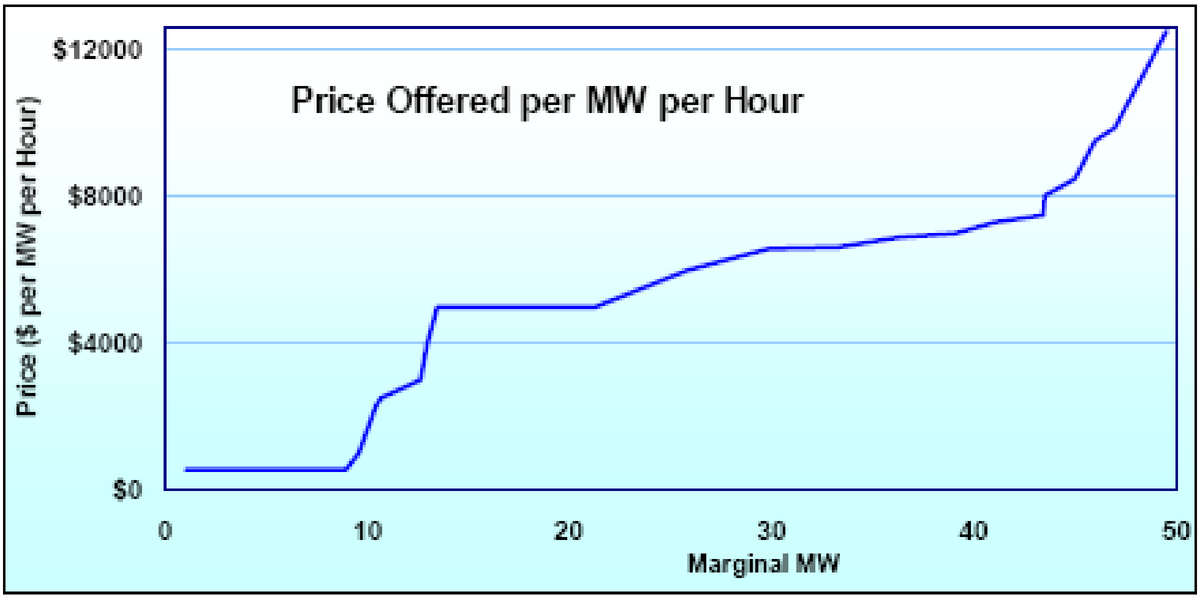


Figure 4: Cost per MW per hour for each additional MW

Source: Transpower

E.72 Again, these offers represent voluntary load restraint, which would be expected to have a cost that is below that incurred during involuntary load shedding.

Emergency load shedding scarcity price – international data

E.73 A number of overseas markets with an energy-only design apply a scarcity value during shortages. Table 10 summarises this information[155]. The data provides a point of comparison, but it is important to note there are differences among these markets. For example, in the case of Texas the scarcity value is also an offer cap, but the cap does not apply to generators with market shares of less than 5%.

Table 10: Scarcity price values

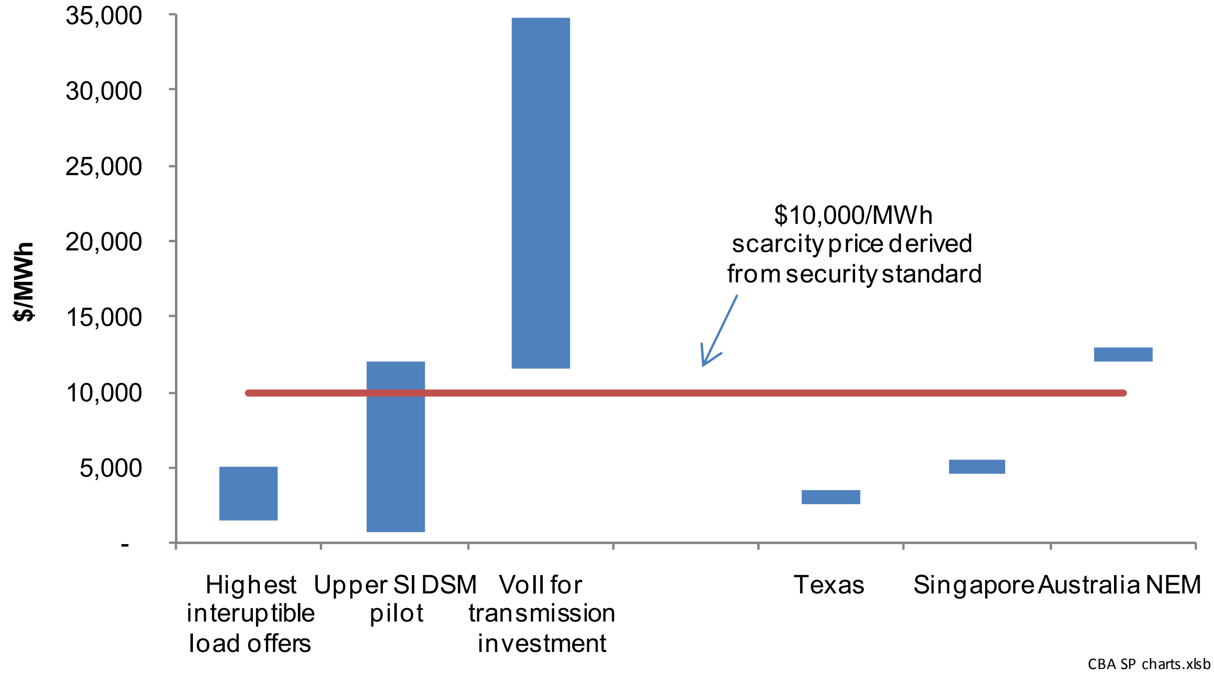
	Local currency	NZD	Exchange rate
Texas	3,000	4,760	0.63
Singapore	5,000	5,021	1.00
Australia NEM	12,500	14,609	0.86

[155] Values have been converted at 10 year average exchange rates.

Emergency load shedding scarcity price – summary

E.74 Figure 33 depicts the $10,000/MWh scarcity price derived from the New Zealand security standard, and shows how this estimate compares to other New Zealand data and overseas scarcity price values.

Figure 33: Summary of scarcity value information – emergency load shedding



E.75 In summary, a scarcity price of $10,000/MWh for emergency load shedding would be above observed offers for voluntary interruptible load, and toward the upper end of the offered prices for contracted demand response in Transpower's Upper South Island demand side management pilot. The value would be well below the mid-point estimate for the Value of Lost Load used for transmission investment appraisal. However, as noted earlier, the nature of the curtailment events may differ, and a $10,000/MWh scarcity value would be relatively close to the bottom of the VoLL range. Lastly, a $10,000/MWh scarcity price would sit within the range of values observed for other markets with an energy only design.

E.76 In light of these factors, a scarcity price of $10,000/MWh for emergency load shedding would appear to be a reasonable.

Floor price for rolling outage load shedding

E.77 The previous sections focussed on the scarcity price for emergency load shedding in times of *capacity* scarcity, where forced curtailment would occur with little or no warning. This section discusses scarcity prices for application in rolling outages during times of *energy* scarcity.

E.78 Rolling outages are load curtailment instructions that can be triggered as a last resort to avoid emergency load shedding. The key features of rolling outages are:

- there would be a declaration of the intention to trigger rolling outages before they are implemented;
- rolling outages could be directed to achieve power savings of up to 25%;
- the System Operator would liaise with electricity distributors and direct-connect users to implement rolling outages;
- rolling outages could be required to address a sudden event with prolonged consequences (e.g. loss of a major infrastructure item) or a developing situation (e.g. a prolonged and severe drought);
- rolling outages would be implemented by:
    - electricity distributors cutting feeders that supply lower priority loads for defined periods (typically hours); and
    - direct connect users shedding load at their sites.

E.79 The reasons for adopting a separate value for rolling outages to that adopted for emergency load shedding are:

- Duration - the duration and timing of rolling outage curtailments would be managed, to the extent feasible, to minimise the resulting costs to society. For example, it is expected that cuts to residential and commercial feeders would be for a number of hours, and would generally avoid the hours of darkness to minimise risks to health and safety;
- Prior notice - cuts would be signalled in advance. This should allow electricity users with the most critical needs (and therefore with the highest curtailment costs) to take mitigating actions. For example, this could allow commercial users to reschedule processes to reduce disruption; and
- Targeting - cuts would be targeted, to the extent feasible, across distribution feeders and grid exit points in a manner designed to reflect the assessed priority of interruption to different customer groups. For example, it is expected that distribution feeders serving critical users would be in the last categories to be curtailed.

E.80 The following sections seek to quantify these effects as far as practicable.

Duration of individual load shedding events

E.81 International studies of curtailment costs generally indicate that the *average* cost of energy curtailed will fall as the period of outage increases[156]. For example, the costs associated

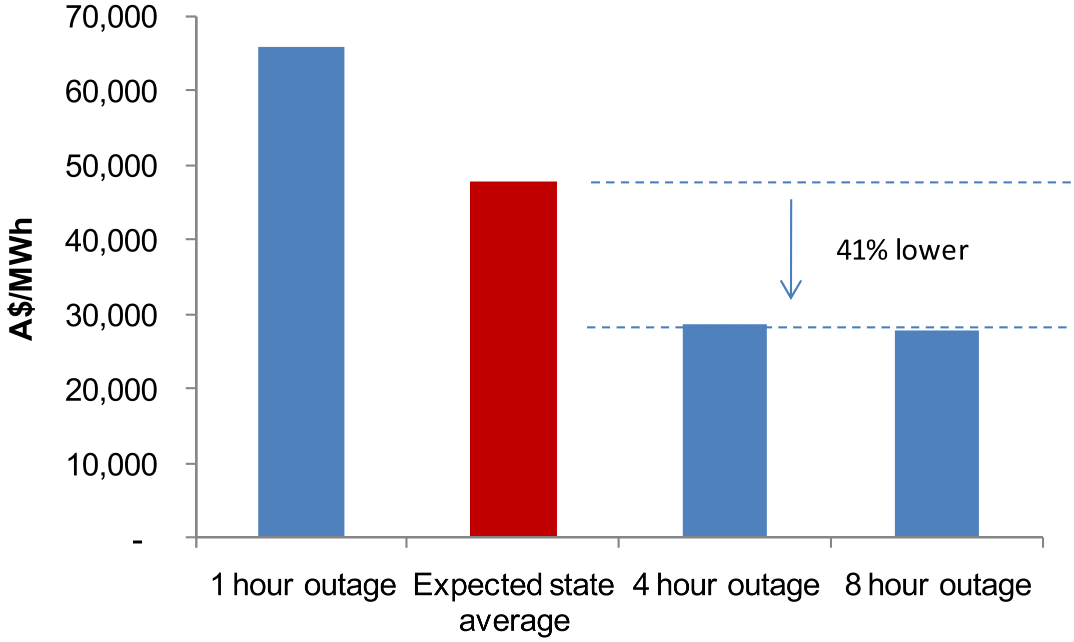
[156] The position can clearly vary across customers and for different events. Nonetheless, this general pattern is expected to apply and is evident in many international studies of VOLL.

with a two hour load shedding event are likely to be lower than the aggregate cost from two separate one hour events, even if the same amount of energy would be curtailed overall.

E.82 This reflects the fact that there are fixed disruption costs associated with a curtailment. Once these costs are incurred, the average cost (in terms of $/MWh of load shed) will tend to decline as the curtailment extends[157]. This is an important issue with rolling outages, as the duration of feeder cuts would be expected to take account of this issue.

E.83 While the impact will vary by event, an indication of the *relative* difference between shorter and longer load shedding events is provided by assessing estimated curtailment cost data for Victoria, as shown in Figure 34. Curtailment events of 4 or 8 hours had expected average curtailment costs that were less than 50% of the expected average cost for 1 hour events. Similarly, the 4 and 8 hour events had expected average curtailment costs that were around 40% lower than the expected average cost used for transmission planning purposes.

Figure 34: Expected cost of curtailment by event duration



Source: Assessment of Value of Customer Reliability, CRA International, 2008

E.84 A number of other international studies have examined this issue, and found broadly similar results, though generally at a somewhat lower level (around 30% appears to be not uncommon). For purposes of this analysis, a 30% difference due to duration effects has been adopted as the central assumption. The effect of sensitivity testing on aggregate results is discussed in a later section.

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157 However, the cost may also rise in some instances as outage duration lengthens. For example, this is likely to be the case for aluminium smelting (as pots freeze) and for food processing and households if refrigeration/freezing capacity is lost for an extended period, and goods are spoiled. In these cases, very significant costs may be occurred if outage duration extends beyond a critical point. Beyond that point, the *average* shortage cost may begin to decline.

E.85 A further issue to consider is whether the cost of shortage declines over time if electricity users face repeated outages. It seems likely that this would occur, as users are likely to make alternative arrangements, such as procuring gas-fired barbeques for cooking etc. This effect has not been included in the estimate noted above.

Pre-notification of curtailment

E.86 Another factor that is expected to reduce the relative cost of rolling outages is the fact that customers would be notified of cuts ahead of time. Unfortunately, unlike event duration which has been examined in a number of international studies, little empirical research has been identified on this issue. This may reflect the fact that most electricity systems are capacity constrained, and therefore little warning can be provided of impending forced load shedding.

E.87 The only identified study which addresses the issue of prior notice is from Norway. That study[158] reported estimates of curtailment costs for planned and unplanned outages at the distribution level for a variety of customer groups. The cost reductions ranged from 10% for residential consumers, to over 30% for commercial users. The study also reported an *increase* in costs for agricultural users experiencing planned versus unplanned outages[159]. The average reduction in costs across all customer groups (excluding agriculture) for planned versus unplanned outages was 21%. This estimate has been adopted as the central assumption. The effect of sensitivity testing on aggregate results is discussed in a later section.

Targeting of rolling outages

E.88 Some information is available on the extent to which rolling cuts could be targeted across different electricity users. Network companies and direct connect users were required to provide 'Participant Outage Plans' pursuant to the Electricity Governance (Security of Supply) Regulations 2008[160].

E.89 These plans set out how participants expected to achieve differing levels of required savings. In particular, the plans set out the extent to which different categories of demand would be affected by differing levels of demand curtailment. The broad priority groups are set out in Table 11.

[158] Reported in *Quality of Supply in Energy Regulation Measurement, Assessment and Experience from Norway*, C. Growitsch et al, University of Cambridge, Electricity Policy Research Group, July 2009.

[159] The reason for this result is not discussed in the study cited above, and the original underlying study is only available in Norwegian.

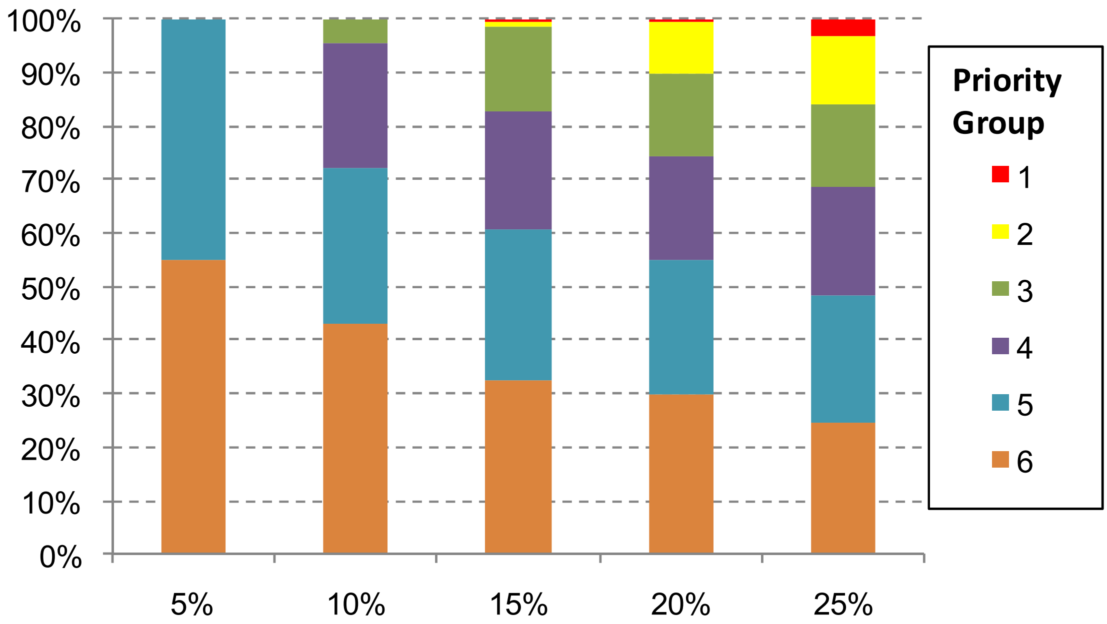
[160] These requirements are now set out in Part 9 of the Code.

Table 11: Broad priority categories for rolling outages

Priority	Priority Concern	Maintain Supply to:
1	Public health and safety	Major hospitals, air traffic control centres, and emergency operation centres.
2	Important public services	Energy control centres, communication networks, water and sewage pumping, fuel delivery systems, major ports, public passenger transport and major supermarkets.
3	Public health and safety	Minor hospitals, medical centres, schools, and street lighting.
4	Animal health and food production/storage	Dairy farms, milk production facilities, chicken sheds and cool stores.
5	Domestic production	Commercial and industrial premises.
6	Disruption to consumers	Residential premises.

E.90 The information from approved South Island network company plans was collated to identify the likely mix of priority groups to achieve differing levels of savings. This information is shown in Figure 35 in the form of a bar for each level of saving (5% to 25%). It is important to note that where AUFLS requirements are maintained by feeders in lower priority groups, rolling cuts may affect higher priority groups than illustrated, and therefore incur higher costs.

Figure 35: Expected mix of priority groups for differing savings



E.91 The chart indicates that the extent to which different priority groups would be affected by rolling outages will be strongly influenced by the required aggregate level of savings. If savings of 10% or less are required, it appears that outages would largely be limited to Priority Groups 5 and 6. As the level of required savings rises, the coverage of affected Priority Groups would increase.

E.92 An indicative analysis has been carried out for the South Island to assess the likely depth of rolling outages that might be required. The analysis indicates that in most cases the cuts would be 10% or less, but that larger cuts cannot be ruled out.

E.93 Looking ahead, the existing constraints limiting North Island to South Island flow are expected to lessen with planned transmission investment. An analysis of the national position post the HVDC upgrade would be expected to show a greater ability to target curtailment across customer groups, because hydro inflow variability is a lower ratio of aggregate national demand.

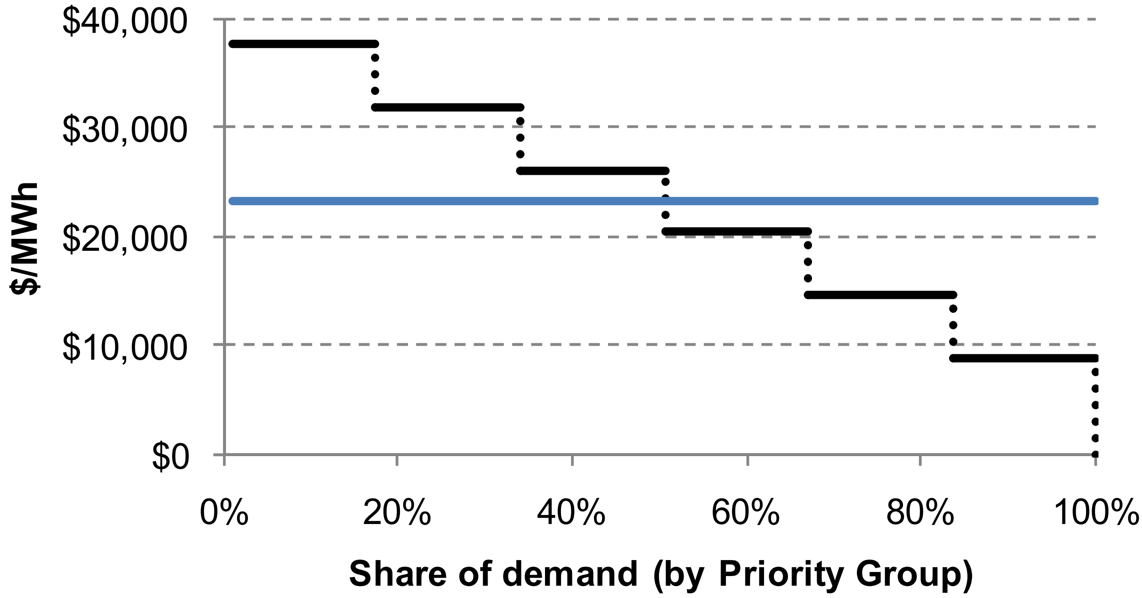
Rolling outages – combined effect of duration, notice and targeting

E.94 A simple model has been applied to combine effect of duration, prior notice and targeting on rolling outage costs. The model assumes the *weighted average* cost of unplanned cuts across all priority groups will equate to the estimate of VOLL used for transmission planning purposes ($23,185/MWh). This value has been used as the ‘anchor’ because the cost reduction ratios for duration and prior notification effects noted above were generally referenced against international studies undertaken for transmission investment purposes.

E.95 The average cost for individual priority groups can be higher or lower than this figure, but the weighted average is assumed to equate to $23,185/MWh. While there is no data available on the relative curtailment costs of *priority groups* per se, many international studies report significant variations in the VOLL estimates for different *customer types*. A number of these studies report differences of 50 times or more between the customer types with the highest and lowest curtailment costs. The cost range for priority groups might be less divergent than for customer types, given the greater homogeneity of the latter. However, it might also be argued that priority groupings, by their nature, allow more differentiation. In light of these uncertainties, a range of possible cost differences across priority groups has been modelled.

E.96 Figure 36 illustrates the shape of an inferred cost function (for un-notified shortages) if there was a fourfold cost range between highest and lowest priority groups, each group had an equal share of overall load, and curtailment costs rose in even steps. As noted earlier, the weighted average (indicated by the blue line) across all priority groups remains $23,185/MWh.

Figure 36: Illustrative cost curve



E.97 A range of these indicative cost functions has been developed for priority groups, based on differing assumptions about the steepness of the cost curve[161]. This information has been combined with the Participant Outage Plan information to compile estimates of the curtailment costs for differing levels of rolling outage.

E.98 Finally, these results have been adjusted to reflect the effect on expected costs of load shedding duration (based on a 30% reduction noted earlier) and pre-notification (based on the 21% reduction in the Norwegian study)[162].

E.99 Figure 37 shows the combined effects of these factors on estimated curtailment costs from rolling outages. The lines on the chart show the effect of varying the 'slope' of the curtailment cost function. In light of the inherent uncertainties, a +/- 25% variations in the estimates has also been applied. This is shown by the shaded area in the chart.

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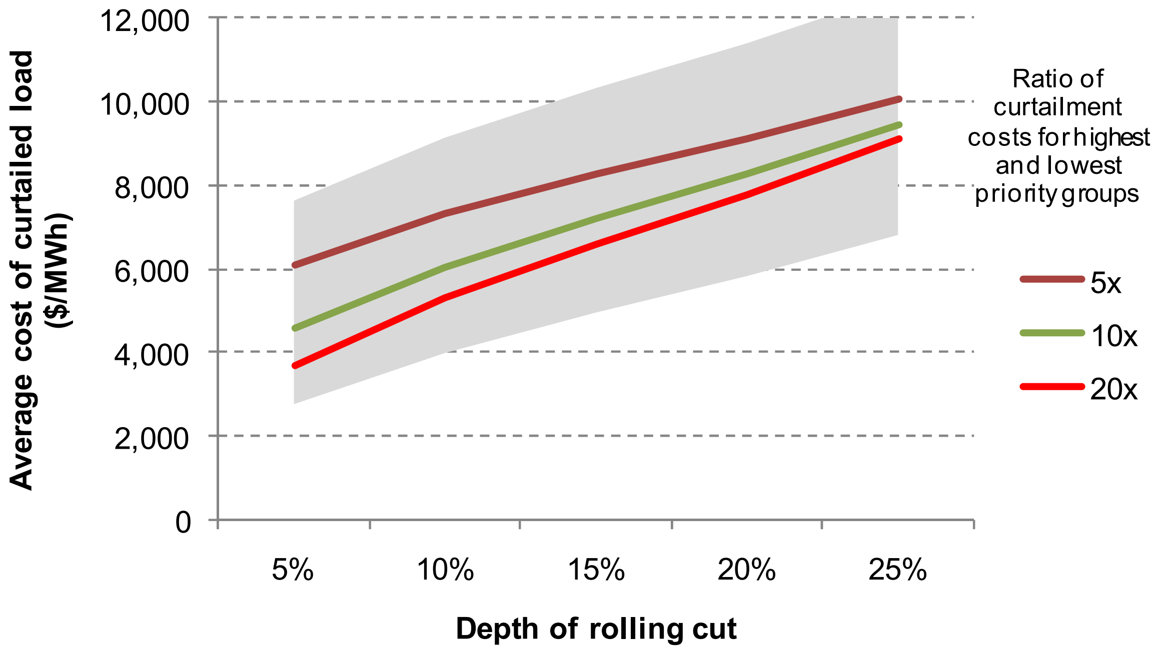
[161] It would also be possible to alter assumptions about the relativities between steps, and relative shares of overall load. However, these effects are picked up to an extent in altering the steepness of the curve.

[162] In the absence of specific information, This approach implicitly treats each effect as being independent.

Figure 37: Estimates for rolling outage cost



E.100 This information suggests that:

- the expected cost of curtailment is likely to be significantly influenced by the depth of any rolling outage cut that is applied;
- the expected cost of curtailment is likely to be significantly lower than for unplanned load shedding.
- on the basis that the scarcity price for rolling outages would be applied as a *floor*[163], the analysis indicates that a floor value of approximately $3,000/MWh would be appropriate.

E.101 Finally, it is important to emphasise the caveats with this analysis. In particular, in the absence of observable New Zealand data, it rests on a number of assumptions about the relativities in curtailment costs across priority groups, and the effects of prior notice and duration on curtailment cost. For this reason, it is prudent to also consider other indicators in seeking to determine a scarcity price floor for rolling outages.

Impact on voluntary demand side response incentives

E.102 Another factor in setting a scarcity value for rolling outages is the desire to minimise any adverse impact on incentives for demand-side participants to undertake voluntary price-based energy conservation measures. For most electricity users, relatively little information

[163] A floor is appropriate because of the significant variation in expected costs associated with differing levels of required saving. A floor would also ensure that prices could be higher if required to reflect a coincident shortage of capacity – i.e. a need to apply un-notified emergency load curtailment to address an unexpected contingency.

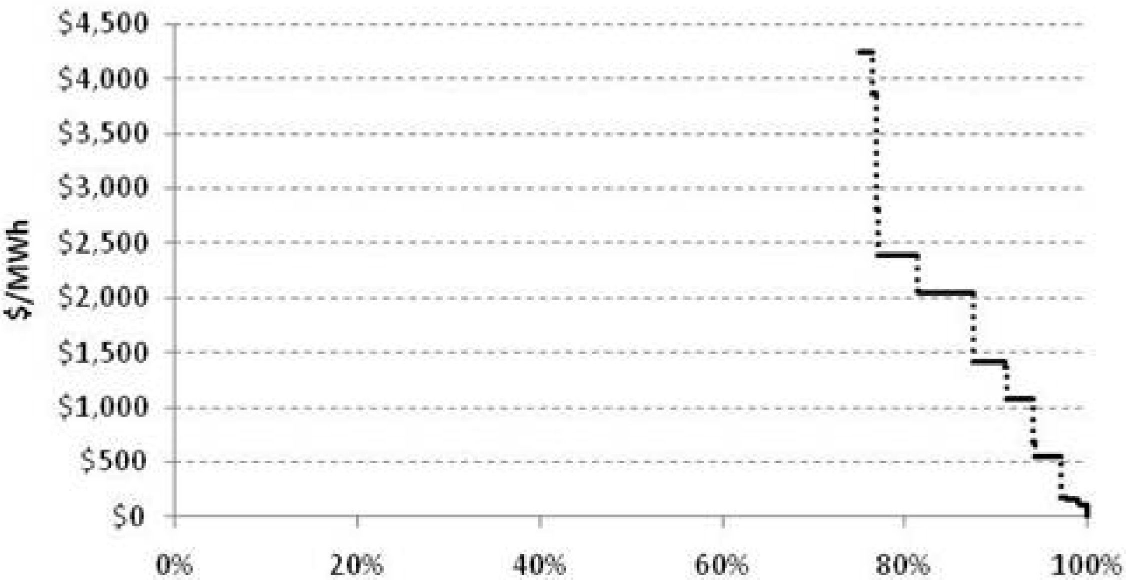
is available in this area. However, for large direct connect users, some information is available from Participant Outage Plans. The plans can take one of two forms:

- Full information plans: Among other matters, this type of plan must contain information on the expected costs associated with different levels of savings; or
- Partial information plans: these plans are less comprehensive, and may exclude information on expected costs.

E.103 Specified direct-connect users have an incentive to submit a full information plan because where authorities seek a relatively low savings target (e.g. 5%), it is possible that this could be achieved by cutting supply to lower priority customers within distribution networks. This could mean that direct-connect users might not be required to make additional savings in that event.

E.104 The cost data contained within available plans was aggregated to produce estimated curtailment costs for energy savings of up to 25%[164]. This information is shown in Figure 38.

Figure 38: Disclosed cost of demand savings - direct connect consumers



E.105 The data suggests that demand savings of around 20% could be feasible at costs of $2,000/MWh or less. These would presumably occur in advance of rolling outages, assuming a price floor of around $3,000/MWh was applied. The chart also indicates that there are some higher cost energy savings options available to these users – in the range $2,500- $4,250/MWh, which could be initiated around the time of rolling outages if required.

E.106 Although the data is not determinative, this relative ordering of potential demand response actions appears to be broadly reasonable. In particular, a price floor set at $3,000/MWh

[164] The chart includes the results from all plans where data was disclosed. It is expressed as percentages of total demand for the relevant parties. The figures for Tiwai assume a 4 week event duration.

would provide room for substantial price-based demand response in advance of rolling outages for these users.

Impact on generation incentives

E.107 As noted earlier, a last resort capacity provider is expected to earn some revenue during periods of fuel/energy constraint (i.e. 'dry years').

E.108 An underlying assumption in that analysis was that spot prices would be $3,000/MWh or higher in rolling outages. If the scarcity price mechanism for rolling outages did not allow this to occur, it could affect the expected economics for a last resort provider.

E.109 A floor price in rolling outages at $3,000/MWh would be consistent with this analysis.

Floor price for rolling outages - summary

E.110 The key observations from the preceding analysis are:

- the curtailment costs associated with rolling outages are expected to be substantially below the cost for un-notified outages;
- the curtailment cost is expected to vary, according to the level of power savings being required from rolling outages (which can be up to 25%);
- the available data suggests a floor price for rolling outages of around $3,000/MWh would be reasonable.

Floor price for public conservation campaigns

E.111 A possible element for adoption is a price floor to be applied when public conservation campaigns are in operation and the risk of shortage is 10% or greater[165]. It is proposed that this floor would be set at $500/MWh. This section sets out how the $500/MWh figure has been derived.

Linkage with risk curves

E.112 The Authority has previously determined that the trigger point for starting public conservation campaigns will be hydro storage[166] falling below the 10% risk curve, i.e. the point where the system is judged to face a 10% risk of shortage in the absence of further measures. The

[165] This would be subject to the minimum geographic threshold discussed in section 5.4.

[166] Note that although the trigger is framed in terms of hydro storage, thermal fuel availability is also important. This factor is taken into account in calculating the position of the risk curves, because it will alter assumptions about thermal generation capability.

Authority has also determined that campaigns will cease when storage has returned above the 8%[167] risk curve.

E.113 The hydro risk curve concept was developed by ECNZ and later used by the Electricity Commission as a means of assessing near-term energy security[168]. Responsibility for monitoring near-term energy security now rests with the System Operator. The methodology for developing risk curves was described in a 2009 Electricity Commission paper[169].

E.114 In brief, assumptions are made about a number of core variables:

- future demand is projected, with an allowance for voluntary price-based conservation;
- geothermal, cogeneration, wind, and small hydro plant operate at full output (subject to assumed outages and any known constraints);
- thermal plant operates at maximum levels to meet demand, subject to adjustments to capacity for planned and forced outages, fuel constraints and transmission constraints; and
- storable inflows are conserved wherever possible (i.e. storable inflows become the balancing item).

E.115 Given these core assumptions, supply and demand can be simulated over the year based on all historic inflow sequences[170]. This information can be used to calculate the starting storage requirement on any given date to just avoid future shortage for each historic inflow sequence. This in turn can be used to generate a distribution of storage requirements for a range of starting points throughout a year (usually the 1st of each month). Storage requirements for "dry" sequences will be higher than those for "wet" sequences, which will have a low or zero storage requirement.

E.116 For a given storage level in any month, it is possible to use this distribution of storage requirements to estimate the risk of future shortage. For example, if a given initial storage level for a given month resulted in 4 out of the 74 sequences running out of storage, then the hydro risk would be 4/74 = 5.4%. Conversely it is possible to use this technique to estimate the storage level for a given month that would correspond to a particular hydro risk (e.g. 10%). Given that expected inflows and demand vary throughout the year, the hydro risk curves also vary through the year. The result of applying this approach is illustrated in Figure 39.

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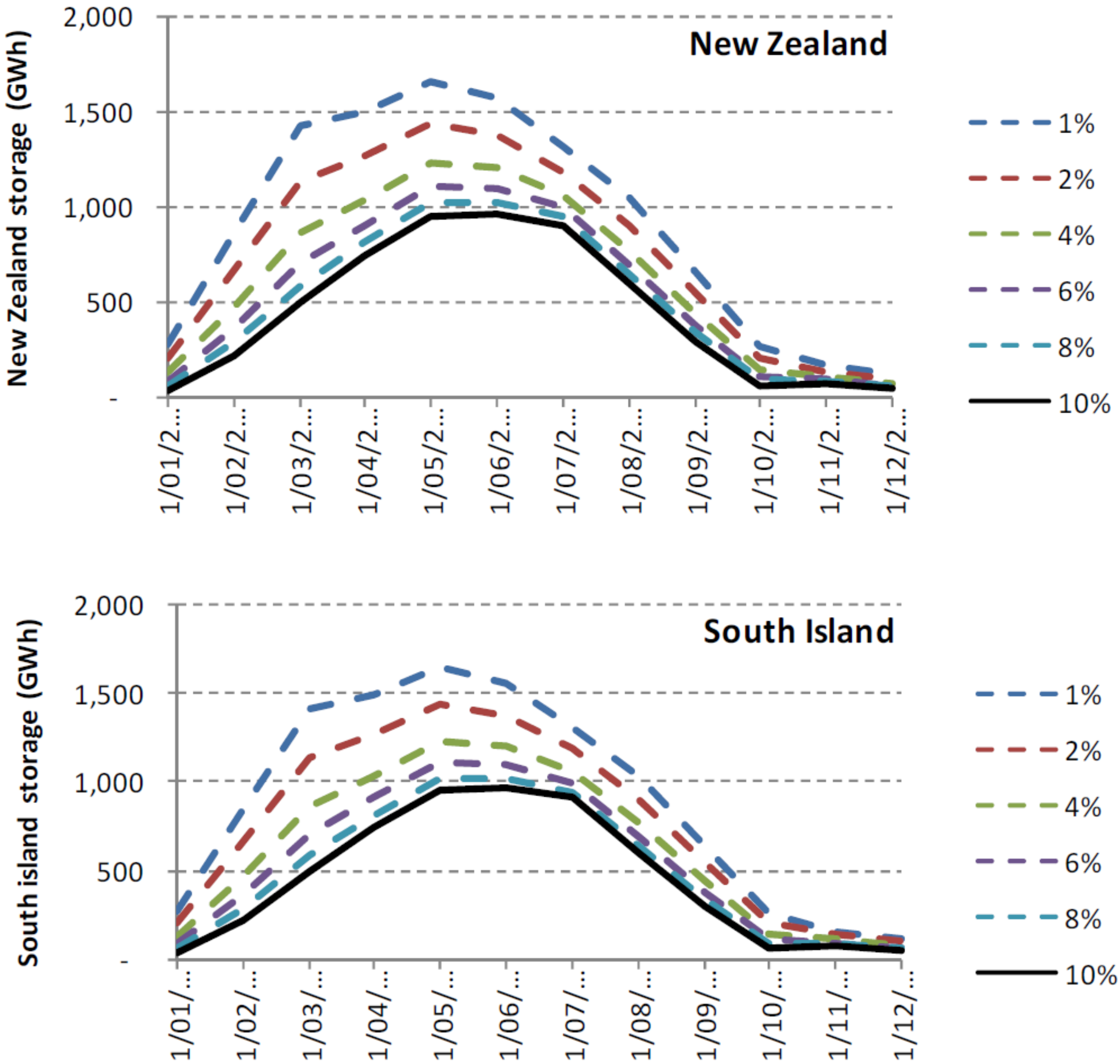
[167] See www.ea.govt.nz/consumer/customer-compensation-scheme/ for more detail. Given these trigger points, it is possible that a campaign might still be running (for a short time) even though the risk of shortage has decline below the 10% level. It is proposed that any price floor would cease to apply once shortage risk returns to 10%,

[168] See "Hydro risk curves and reserve energy dispatch guidelines", *Electricity Commission*, June 2009 http://www.ea.govt.nz/document/2229/download/industry/ec-archive/security-of-supply/security-of-supply-policies-archive/

[169] No adjustment is made for additional demand response such as that from savings campaigns or the impact of additional supply/reduced demand from implementing emergency measures.

[170] There were 74 inflow sequences for this original analysis.

Figure 39: Hydro risk curves (illustrative)



Deriving a price floor for the 10% risk curve

E.117 Given that the Authority has previously determined that the trigger point for starting public conservation campaigns will be hydro storage falling below the 10% risk curve, the appropriate value for a price floor at the 10% risk curve level should be the water value at that level, i.e. the economic value of conserving storage now for release at a later date.

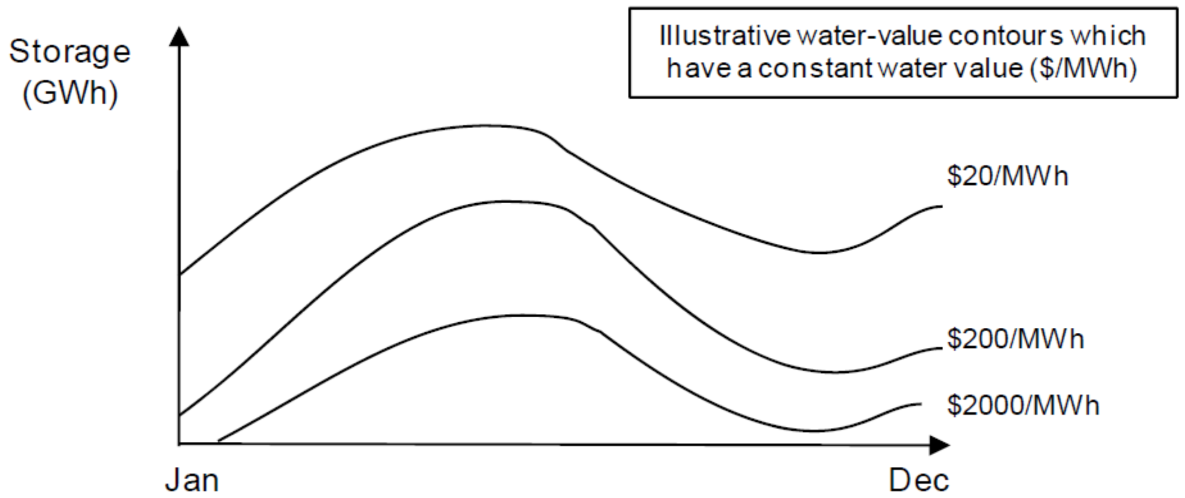
E.118 The water value associated with a particular level of storage at a given time of year can be derived by simulating the operation of the electricity system over a full range of future scenarios (for example, hydro inflows, demand patterns and generation plant availability) and assessing the extent, duration and cost of different levels of demand restraint required

E.119 In many cases, inflows will be such that lake levels rise, no additional demand restraint is required and higher cost thermal generation can be backed off. However, there is also a risk that inflows remain low and that additional more costly demand restraint will be required. A water value will reflect the expected value of all these outcomes.

E.120 In New Zealand, water values tend to increase going into winter as demand is higher and hydro inflows start to decline. They tend to fall during the spring when inflows are typically highest and demand is falling due to seasonal effects.

E.121 A water-value contour can be created by determining the storage levels over the year that have the same water value. A hypothetical set of water value contours is illustrated in Figure 40.

Figure 40: Illustrative water value contours



E.122 There are a number of different methods that can be used to derive water value contours. These have been used extensively in New Zealand over the last 20 years and include variants of dynamic programming developed by Dr Grant Read and a number of his students.

E.123 When the Commission undertook the hydro risk curve work in 2009, it chose to use a single reservoir version of the constructive dual dynamic programming (CDDP) as described in T. J. Scott and E. G. Read (1996) and T J Scott (1997). This approach has the advantages that it is relatively simple to implement[171], it can be solved very quickly and is well suited to incorporating continuous demand response curves. It can also utilise the same set of market simulations that were used to derive the hydro risk curves described above.

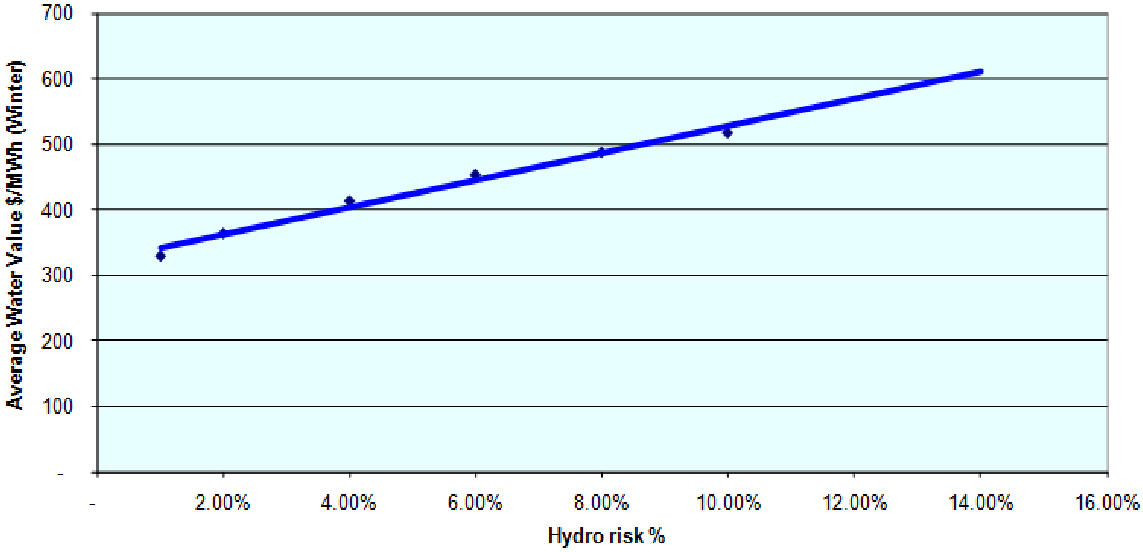
E.124 In light of these factors, the approach used in 2009 has been updated to reflect more recent information. In particular, an illustrative case for 2014 has been compiled which incorporates

[171] It was not considered worth the effort of implementing or adapting more complex multi-reservoir models such as RESOP (Read 1985, 1990) given that water value curves above the variable operating costs of reserve energy plant are most relevant and the inherent uncertainty in shortage and future oil costs.

the effect of an expanded HVDC link (based on the Pole 3 upgrade) and revised shortage costs to account for inflation since 2009.

E.125 The effect of applying these revisions is shown in the chart below Figure 41 which depicts the relationship between hydro risk curves and corresponding average water values[172]. Based on the 10% hydro risk curve, the corresponding average water value is approximately $500/MWh.

Figure 41: Average water values for each hydro risk curve



Other comparators – floor price for public conservation campaigns

E.126 It is useful to consider other points of comparison in setting a floor price for public conservation. These include:

- the most expensive thermal generation source in terms of short run marginal cost is an oil-fired peaker. This has a short run marginal cost of approximately $400/MWh. A $500/MWh floor for public conservation campaigns would imply that these are invoked only after all available thermal generation is likely to be operating. This appears reasonable in terms of the expected 'merit order' of thermal plant operation and public conservation measures; and
- the variable charge in residential supply contracts is approximately 20-25 cents/kWh, which equates to $200-250/MWh. Given that consumers presumably value consumption at greater than the variable charge (and less than the value of lost load), a floor price of $500/MWh does not appear implausible.

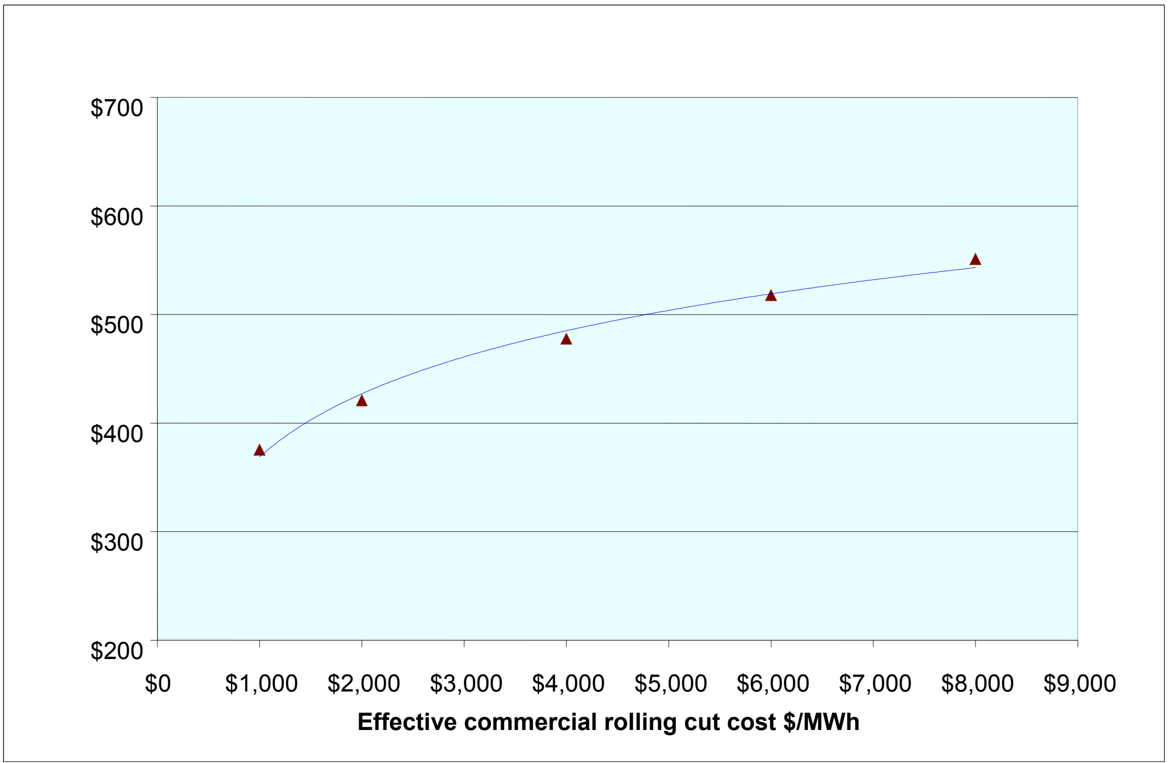
172 Water values for any given hydro curve vary across the year, but are relatively stable over the critical winter months, The chart shows the average of values for the April to July (inclusive) winter period.

E.127 In light of all these factors, it is proposed that the floor value be set at $500/MWh, if a price floor is adopted for public conservation campaigns.

Sensitivity testing - floor price for public conservation campaigns

E.128 While the factors discussed above support $500/MWh as the price floor for public conservation campaigns, experiments with different simulation models indicate that water valuation below the 2-4% hydro risk curves can be sensitive to input assumptions. This sensitivity is illustrated in Figure 42, which shows how water values vary with the assessed cost of shortages (i.e. the *expected* spot price in rolling outages)[173].

Figure 42: Impact of effective rolling cut price on the water value at the 10% HRC



E.129 The potential sensitivity of estimated water values to changes in assumptions is a double edged sword. First, it makes it more difficult to estimate the appropriate level for a potential price floor. However, market participants' own water value models will also be sensitive to input assumptions. This increases the likelihood that participants inadvertently 'mis-estimate'

[173] This is the cost reflected in spot prices, and may differ from the social cost for a variety of reasons. These include factors such as the risk of market suspension or intervention, market behaviour, absence of an obligation to compensate customers who are forcibly curtailed etc. The chart was prepared using the simplified water valuation approach used in the 2009 analysis and referred to earlier.

system costs at the 10% risk level, relative to the ideal from society's perspective. This could raise the likelihood of public conservation campaigns or rolling outages being required.

E.130 For these reasons, it is important to consider the consequences of mis-estimating the value for a floor price. If the level is too low, this would be expected to have little or no effect (assuming participants did not treat the level as 'guidance'). Conversely, setting the floor price at too high a level would be expected to:

- increase hydro storage levels somewhat, and increase the risk of hydro spill requiring additional thermal fuel use;
- increase the use of relatively expensive fuel (such as oil) to conserve hydro storage earlier than otherwise;
- increase market prices earlier than otherwise during "near-misses" and result in more voluntary market based demand response; and
- possibly bring forward additional hydro firming capacity with its associated capital cost.

E.131 These additional costs would be offset by the value of any incremental reduction in costs associated with public conservation campaigns or rolling cuts.

E.132 The relative sizes of these offsetting effects can be assessed in broad terms using system simulation models. This has been carried out, assuming the floor price was too high and that this raised the South Island storage requirement by 200 GWh (approximately 7%) at the $350/MWh water value. The estimated effect on supply costs[174] and the offsetting benefit from reduced public conservation campaigns and rolling cuts[175] will depend on the system margin. The results under different system margin assumptions are set out in Table 12.

Table 12: Net cost of setting the floor price too high

Winter Energy Margin	17.0%	20.3%
Spill Cost $m/yr	$2	$1
Increased oil and voluntary demand response $m/yr	$6	$2
Change in shortage cost $m/yr	-$5	-$2
Net Cost $m	$2	$1

E.133 As can be seen there would be a net expected cost of around $2 million per annum of getting the $350/MWh guideline too high by 200 GWh, if the system was just reaching the energy standard, but this would fall to around $1 million per year if New Zealand is largely *capacity*

174 The $3.5m was derived from an illustrative system at a 20.3% WEM (similar to current) and $7m for a 17% margin (the optimal standard).

175 This assumes rolling cuts have a social cost of $6000/MWh, and public conservation campaigns have an average cost of $800/MWh.

constrained, and the *energy* margin increased to over 20%. In summary, it appears likely that the net impact of mis-estimating the level of the floor price would not be large, because of the offsetting effects on supply cost and expected shortages.

Scarcity price values – addressing overall uncertainties

E.134 All of the scarcity price values discussed above are clearly estimates. While further analysis might narrow some uncertainties, a number of unknowns will inevitably remain. From a practical perspective, it is not realistic to expect analysis and modelling techniques to provide a complete answer in setting scarcity price values. There will necessarily be an element of judgement required.

E.135 In this respect, the experience with the scarcity pricing regime in Australia provides potential guidance to addressing uncertainties from a *process perspective.* Although the regime has been in place since 1998 and has undergone periodic reviews that draw heavily on analytical techniques (many of which have been used for this paper), there is still a strong element of judgement required when it comes to determining scarcity price settings.

E.136 In the Australian NEM, that judgement rests finally with the Australian Energy Market Commission (the rule maker) and the AEMC Reliability Panel, comprised of supply and demand side experts[176]. The AEMC Reliability Panel also consults widely about prospective changes before making any recommendations.

E.137 The experience with the most recent review provides an indication of how the process works in practice:

- early 2008 – AEMC signals intention to undertake review for settings to apply from mid 2012;
- mid-2009 – AEMC Reliability Panel commences review;
- December 2009 – AEMC Reliability Panel publishes a draft report proposing that scarcity value be increased from A$12,500/MWh to A$20,000/MWh – calls for submissions;
- January – March 2010 – submissions made on draft review – suppliers and purchasers generally oppose increase, based on system performance to date and projected investment commitments and forecast demand;
- April 2010 – AEMC Reliability Panel decides on basis of further information and submissions that existing values should be maintained for next two years, but should be adjusted for inflation.

E.138 In Australia, the process of setting a scarcity value is incremental in nature, with considerable weight being placed on the recent system performance and information presented by stakeholders. In other words, if the system appears to be moving toward an over tight

[176] The Panel is a specialist body within the AEMC and comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on the safety, security and reliability of the national electricity system and advising the AEMC in respect of such matters. The Panel's responsibilities are specified in section 38 of the National Electricity Law.

situation (lack of investment commitments etc), then scarcity values are likely to rise. Conversely, if the system is performing adequately, settings are unlikely to be materially changed.

E.139 There is merit in adopting a similar approach in New Zealand. Accordingly, it is proposed that:

- formal reviews would be conducted at least every three years , and would cover scarcity price values and other key design issues;
- the process for initiating/considering possible changes would ensure that affected stakeholders can provide input before final decisions are made; and
- unless change is necessary to address a genuinely urgent issue, at least 12 months notice would be provided before any changes to scarcity price values take effect.

Appendix F Cost Benefit Analysis

Framework

F.1 This cost benefit analysis draws on the broad framework developed by the New Zealand Institute of Economic Research (NZIER) for the Electricity Commission[177].

F.2 Consistent with the Authority's statutory objective, the analysis is undertaken from an economy-wide perspective, weighing costs and benefits to New Zealand as a whole. Effects that are strictly wealth transfers between parties, although affecting the distribution of costs and benefits, offset each other in the aggregation of total costs and benefits to New Zealand (i.e. where a cost to one party is an equivalent benefit to another party).

F.3 While effects which are solely transfers have not been included as costs or benefits from a national perspective, the Authority has considered the potential impact of scarcity pricing measures on prices and costs to electricity users. This issue is discussed in Section 6.4.1.

F.4 The assessment of incremental costs and benefits has been considered against a counter-factual scenario of existing arrangements, including a number of committed changes which have yet to take effect. These include:

- phasing out the Reserve Energy Scheme, and the sale by the Crown of the Whirinaki reserve generation plant;
- restructuring some of the state owned enterprise generator-retailers by transferring assets and virtual asset swaps;
- establishing an open access trading vehicle for futures contracts and, if necessary, introducing a market maker initiative; and
- enhancing market information and monitoring.

F.5 All values are expressed in real terms (i.e. net of inflation) in current dollars unless otherwise stated. Because scarcity pricing is intended to alter decisions of market participants over an extended period of time, the costs and benefits have been modelled over a period of 30 years. A real discount rate of 8% has been used to convert future costs and benefits to present values[178]. Sensitivity analyses of 6% and 12% have also been applied.

Benefit

F.6 The objective of scarcity pricing is to provide greater assurance that the 'efficient' level of security and reliability will be delivered by the electricity system. The efficient level is the optimum because the cost of achieving a greater level of security would outweigh benefits to consumers, and vice versa. This is shown in illustrative form in Figure 43.

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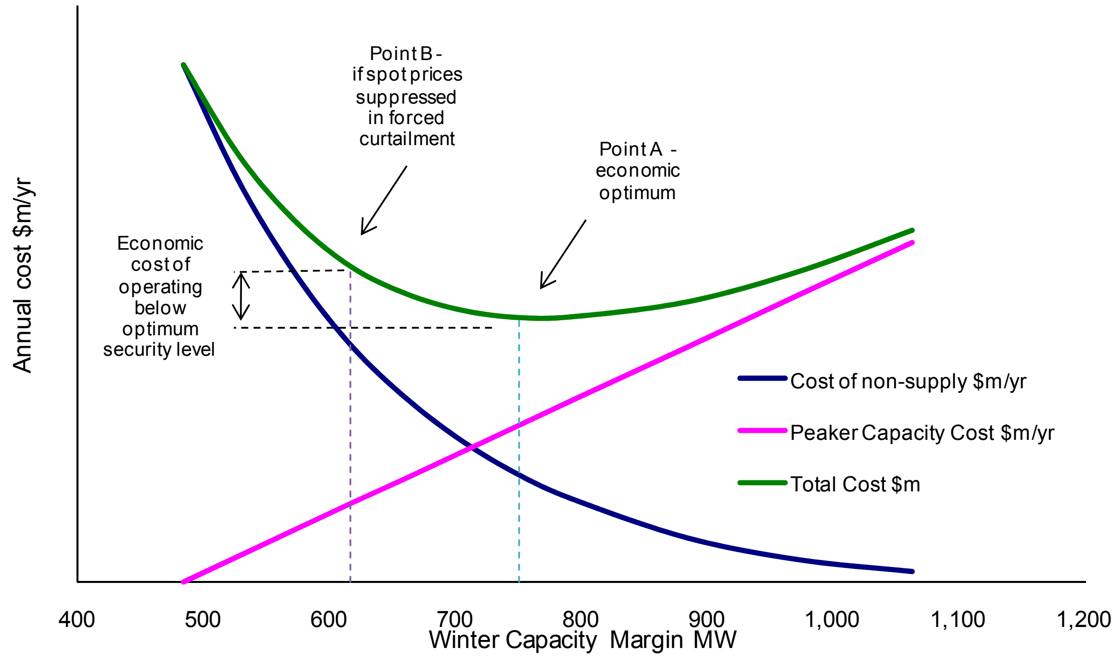
[177] See "An integrated cost-benefit analysis of the market development programme – Working Draft", *New Zealand Institute of Economic Research*, 2010. For example, it uses the same overall economic efficiency framework, discount rates and timeframes for measurement. The basis for estimating the numerical magnitudes for the costs and benefits differs.

[178] This is the rate recommended by the Treasury for cost benefit analysis of energy and water infrastructure projects.

Figure 43: Trade-off between cost of non-supply and cost of supply - illustrative



F.7 This chart shows the 'amount' of security expressed in terms of winter capacity margin[179]. The pink line shows the cost of adding more capacity to increase this margin. The blue line depicts the expected economic cost of non-supply (i.e. voluntary demand restraint or forced curtailment) for differing levels of capacity margin. As the capacity margin increases, the likelihood of requiring curtailment declines. Furthermore, the cost of non-supply is expected to be non-linear, with progressively higher costs as the security margin declines due to increasing frequency and size of demand restraint or curtailment events.

F.8 The green line is the sum of the supply and non-supply cost functions[180]. Point A is the minimum on this curve, and represents the economic optimum from a national perspective. To the extent that the system has a capacity margin to the left or right of this optimum, then overall system costs will be higher than the ideal.

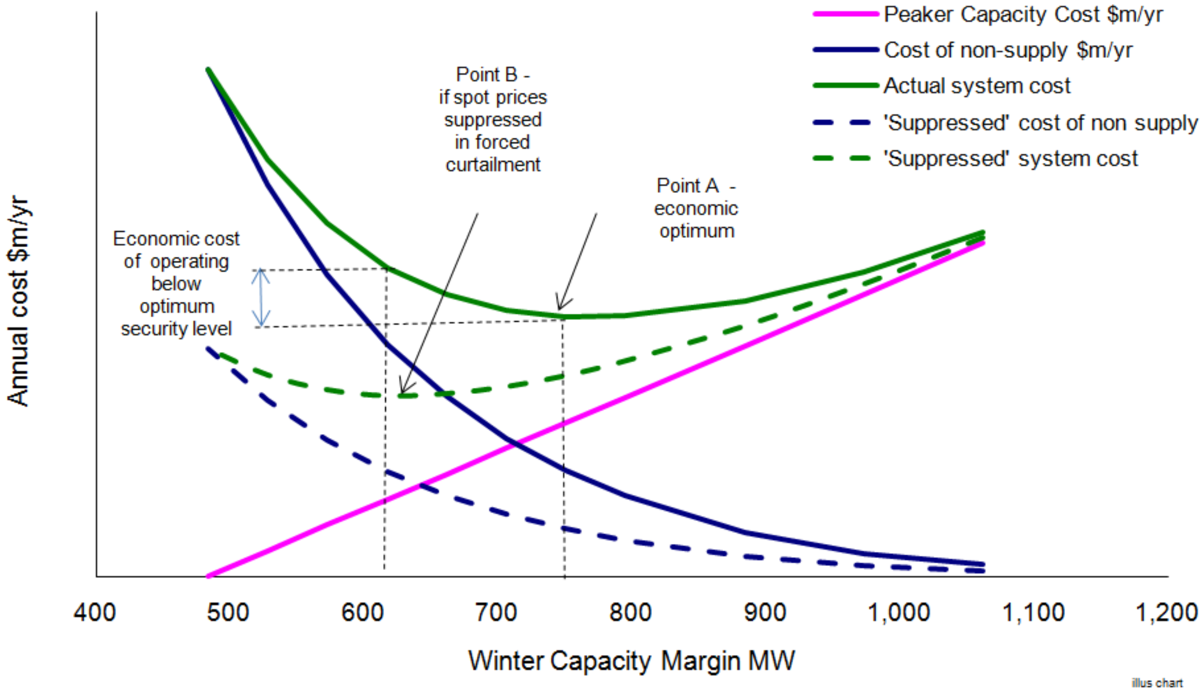
F.9 As discussed in Section 4, current arrangements tend to suppress spot prices during capacity shortfalls. This undermines the incentive to invest in demand side response or generation capacity. This means the system will *on average* tend to have a capacity level that is lower than the optimum point. Relative to the optimum, this would avoid some generation cost, but will increase the expected cost of non-supply. The net difference is an economic loss from a national perspective.

[179] This is one of measures of security defined in section 7.3 of the Code.

[180] In this context, 'total annual cost' refers to the cost of obtaining the last few MW of capacity for the system, not the entire system capacity.

F.10 The extent of this effect cannot be known with certainty, but can be estimated using the framework adopted to derive scarcity prices for emergency curtailments[181]. The advantage of this approach is that the results will be internally consistent, for a given set of assumptions. The key elements of the approach are illustrated by Figure 44.

Figure 44: Estimating effect of price suppression on security margin - illustrative



F.11 Because of price suppression effects, the apparent cost of non-supply signalled in prices to market participants (blue dotted line) is shifted downwards relative to its true level, resulting in the apparent overall system cost (green dotted line) also moving downwards. The 'apparent' minimum cost position for the system is shifted to the left on the chart. The overall result is that the system will tend to operate with a lower capacity margin than the optimum level, with the difference being determined by the extent of spot price suppression.

F.12 The size of the change in system cost (indicated as the 'economic cost of operating below optimum security level') has been estimated based on the spot price assumptions used to derive scarcity price values for emergency load shedding[182].

F.13 As noted in Appendix E, these assumptions reflect the expected changes to spot prices from adopting a $10,000/MWh price floor in grid emergencies, and the proposed changes to pricing in IR shortfalls. Furthermore, the assumptions make allowance for the likelihood that a last resort resource provider will earn some revenue during periods of energy shortage (i.e. dry-years). For this reason, the resulting benefit represents the expected gain from the *combined* effect of the proposed scarcity pricing changes.

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[181] See Appendix E.

[182] See Appendix E.

F.14 Based on the assumptions noted above, scarcity pricing would be expected to yield annual benefits of around $12 million relative to the counter-factual. An alternate counter-factual case has also been included, based on the existing Whirinaki capacity offer price of $5,000/MWh. When measured against the alternate case (which assumes less price suppression and is therefore more conservative[183]), the annual benefit would be around $3 million.

F.15 It is important to note that these estimates represent the expected benefit once the system has reached a steady state[184]. In practice, the benefit is unlikely to accrue immediately, and some phase-in should be allowed.

F.16 In light of these factors, alternative scenarios have been considered where benefits of scarcity pricing are progressively realised over two, three, or five years. This information has been combined to estimate the present value of expected benefits under these various scenarios. This is summarised in Table 13.

Table 13: Present value of benefits

	Number of years before full benefit attained		
Present value of benefit ($m)	5 years	3 years	2 years
Counter-factual	102	111	121
Alternate counter-factual	26	28	31
			CBA SP charts.xlsb

Costs

F.17 The main economic cost associated with scarcity pricing would be the changes required to the market clearing engine. The magnitude would depend on the precise form of scarcity pricing and the way it is implemented within the market software. No firm estimate is currently available for this cost. For the purposes of this analysis, a one-off cost of $4.5 million has been assumed for the changes to the market clearing engine[185].

F.18 An allowance of $100k per annum has also been made for ongoing software maintenance from year two. Finally, an allowance has also been made for costs associated with three yearly reviews. This is assumed to be $500k per review, to cover any costs that are incremental due to scarcity pricing.

F.19 The introduction of scarcity pricing is not expected to give rise to changes to market participants' trading or settlement systems, and no incremental cost has been assumed in this area.

183 The case is included for completeness, but appears somewhat implausible given that the Crown has announced the intended sale of Whirinaki, at which point its offer will be market determined. The Authority has also proposed a reduction in the capacity offer price (subject to pre-conditions), while the plant remains in Crown ownership and under the Authority's control.

184 In other words, these represent longer term equilibrium states – around which the system may vary in the shorter term.

185 As discussed below, although no estimate is currently available, the overall result is relatively robust to variations in implementation costs.

F.20 The cost information is summarised in Table 14.

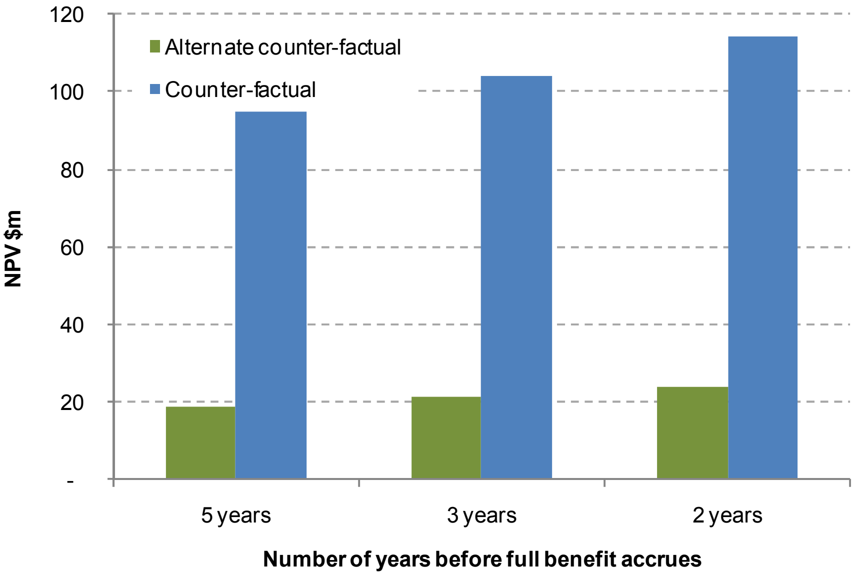
Table 14: Present value of costs

Present value of costs ($m)	
Implementation	(4.3)
Maintenance	(1.1)
Review s	(1.6)
Total	(7)
	CBA SP chart s. xlsb

Net benefit

F.21 The information on benefits and costs has been combined to produce estimates of net benefits, and this is shown in Figure 45.

Figure 45: Estimated cost of non supply and market price curve (without scarcity pricing)



CBA SP charts.xlsb

F.22 The analysis indicates that scarcity pricing is expected to provide a net benefit of approximately $95 million to $114 million, when assessed against the counter-factual[186].

F.23 As a sensitivity case, if the alternate more conservative counter-factual case is used (which effectively assumes continuation of the Whirinaki offer at $5,000/MWh), the net benefit range is smaller but remains positive at $19 million to $24 million.

[186] Recalling that the counter-factual assumes spot price outcomes are similar to those observed prior to March 2010, when the Whirinaki offer strategy was changed to $5,000/MWh. The counter-factual case excludes the effect of the increased Whirinaki offer price after March 2010 because the Government has announced that the plant will be sold, at which point the offer price will be market determined. See Appendix E for more information.

F.24 A further sensitivity case is to consider variations in the level of implementation costs. Even if the overall cost estimate were to double, the net benefit is expected to be positive as shown in Table 15.

Table 15: Present value of net benefits – sensitivity case (costs double)

	Number of years before full benefit attained		
Present value of net benefit ($m)	5 years	3 years	2 years
Counter-factual	88	97	107
Alternate counter-factual	12	14	17
			CBA SP charts.xlsb

F.25 A sensitivity case of alternative discount rates has also been applied. A lower rate of 6% and a higher rate of 12% (which is more reflective of a private sector commercial perspective) were tested. The results (based on a 3 year phase in for benefits) are summarised in Table 16. The present value of net benefits is affected by the choice of discount rate, but remains positive for all of the cases that were tested.

Table 16: Present value of net benefits – sensitivity case (discount rates)

	Discount rate		
Present value of net benefit ($m)	12%	8%	6%
Counter-factual	70	104	131
Alternate counter-factual	13	21	28
			CBA SP charts.xlsb

Conclusion – cost benefit analysis

F.26 When assessed against the counter-factual, scarcity pricing is expected to yield potential net economic gains of approximately $95 million to $114 million, depending on the phase in period for benefits. Even if a more conservative counter-factual is assumed (with less price suppression), the expected potential net benefit range remains positive at $19 million to $24 million.

F.27 It is important to note the results are sensitive to the input assumptions, and there are uncertainties about a number of variables. In particular, these results are based on an assumption that scarcity pricing changes are durable and are perceived as such by market participants. To the extent that this assumption does not hold, the net benefits of the proposals would decline and could even be negative.

Appendix G Potential price capping mechanisms

Purpose

G.1 As noted in Section 7, the Authority has considered a range of potential price capping mechanisms. This appendix describes those potential alternative capping mechanisms in more detail, and comments on the key issues that would arise with them.

Mechanisms to cap overall prices

G.2 Mechanisms to limit prices in wholesale electricity markets can take two main forms:

- offer caps – which place an upper limit on the price at which demand response and/or generation resources can be offered or bid into the market; and
- price caps – which place an upper bound on the spot price to be paid and received by buyers and sellers respectively.

G.3 An offer cap would place an upper limit on the price at which participants can offer their generation or demand-response service. An offer cap could be seen as a default demand side bid at the offeror's node, above which there will be no demand for energy.

G.4 An offer cap would be the simplest option from an implementation perspective. Indeed, existing arrangements already have a de facto offer cap, because the market software will not accept offers greater than $99,999.99/MWh. To introduce a formal offer cap, this limit would be altered to a different value.

G.5 Although an offer cap would be relatively easy to implement and could have some moderating influence on spot prices, it would still be possible for final spot prices to settle at levels well above the offer cap. This is because the market clearing engine calculates final prices based on the marginal cost of serving incremental load at each node. In some cases (e.g. spring washer situations, or where multiple generators are the marginal reserve risk), this can lead to final prices which are much higher than any offer price (see Appendix B for more information).

G.6 Unlike an offer cap, a price cap would have a direct impact on final spot prices and therefore have a more certain effect on prices paid by wholesale buyers. However, a price cap by itself would not place any restriction on offers by generators or demand response providers, and any settlement shortage would be met by constrained on payments under current arrangements.

G.7 A combination of offer and price caps can also be applied, and this appears to be the most common approach in other energy-only markets with scarcity pricing (e.g. Australia and Singapore[187]). The chief advantage of the combined approach is that it provides a high level

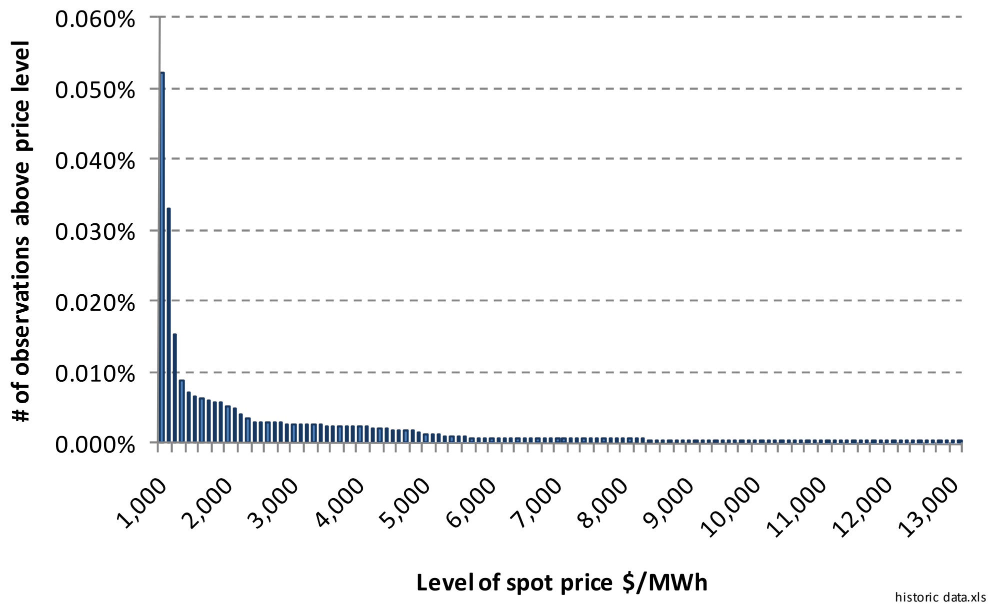
[187] The exact mechanisms vary across markets – but the common features are that final prices are capped, and resource providers are not able to offer in a way that circumvents the price cap. The position in Texas is not entirely clear. The rules clearly provide for an offer cap, but some documents also make references to a price cap. However, it is not clear whether or how this affects wholesale market prices.

of certainty about the upper limit of prices for wholesale buyers and sellers, while ensuring that constrained on payments cannot increase to a point where they negate the effect of a price cap.

G.8 In energy-only markets with scarcity pricing, the cap level is generally set by reference to the scarcity value for forced emergency load shedding. If that approach were adopted in New Zealand, it would suggest an offer cap of $10,000/MWh[188], with a separate price cap at a higher level to allow for differences between injection and off-take prices due to transmission effects[189].

G.9 The key risk with any price or offer capping mechanism is the potential for unintended adverse effects on resource provider incentives. Some *indication* for this potential can be gained by considering the pattern of historic spot prices. Frequent instances of prices above an intended cap level would suggest a cap could adversely affect resource provider incentives, and vice versa. Analysis was undertaken of New Zealand final price data for all nodes with metered generation or load in the period 2000-2010. In total, this comprised approximately 42 million separate observations. Of this total, 106 instances were identified where the final price exceeded $10,000/MWh and 50 where it exceeded $11,100/MWh[190]. Many of these appear to relate to a single trading period, where spring washer effects resulted in high prices at a number of nodes. The 106 instances is equivalent to 0.0002% of the observations. This is illustrated by Figure 46.

Figure 46: Analysis of spot prices for all nodes (2000 - current)



188 It is expressed as an *offer* cap because revenue adequacy for a last resort provider was the primary methodology used for deriving the scarcity value.

189 For example, in Singapore the offer cap is set at 90% of the overall price cap.

190 If an offer cap of $10,000/MWh were applied and this was 90% of the price cap, this would imply a price cap of approximately $11,100/MWh. The 90% ratio is the same as in the Singapore electricity market.

G.10 This data tends to suggest that an overall cap at around $10,000 - $11,000/MWh may not have a marked effect on resource provider incentives. However, the indicator is not determinative because historic data may not be a good guide as to likely future conditions (for example a growing proportion of intermittent generation on the system). The data may also be an unreliable guide because it fails to appropriately reflect past system conditions (for example due to price suppression effects).

Cumulative price threshold

G.11 Some markets apply a cumulative price threshold, which limits the length of time that prices can be sustained at elevated levels. These mechanisms operate by temporarily lowering the general price cap if the rolling average spot price reaches a pre-defined threshold.

G.12 The rationale for this kind of mechanism is based on the following:

- exposure to risk is influenced not just by an overall cap, but also the length of time that prices can be sustained at high levels;
- in electricity systems where price risk is driven primarily by sudden onset events (e.g. a few days of extreme high temperatures), a cumulative price threshold can retain strong incentives for parties to actively manage risk, while also limiting the exposure to extreme risks;
- a cumulative price threshold may assist in mitigating the price risks from weak competitive pressure;
- a cumulative price threshold may lower contracting costs by avoiding the need for wide force majeure clauses and enabling counterparty risks to be more easily assessed and managed. This may in turn facilitate competition from smaller scale and more specialised participants; and
- for very extreme events (e.g. a major earthquake), there may be justification in limiting the financial consequences for market participants. In this context, a cumulative threshold would have a similar effect to force majeure clauses in commercial contracts or suspension provisions in market rules.

G.13 For example, in the Australian market if cumulative spot prices over 7 days reach A$187,500 (an average of A$558/MWh[191]), the price cap is reduced from $12,500/MWh to a level which approximates the expected short run marginal cost of a peaker plant. The normal price cap is reinstated once cumulative prices fall below the threshold level.

G.14 The Texas market includes a provision called the Peaker Net Margin ("PNM") that constrains cumulative prices. If the PNM for a year reaches a cumulative total of US$175,000 per MW, the system-wide offer cap is reduced from US$3,000/MWh to the higher of US$500/MWh or 50 times the daily gas price index.

[191] This is A$187,500 divided by 168 hours. The figure is then halved because the threshold is defined on basis of half hour trading periods.

G.15 A cumulative price threshold would raise the same fundamental trade-off as a general price cap – i.e. balancing the desire to reduce risk, but without undermining incentives for sound risk management and resource provision. From a *capacity adequacy* perspective, analysis of the available data suggests that a cumulative price threshold along the lines of that adopted in Australia should not unduly weaken incentives for resource provision[192].

G.16 However, a different conclusion applies when viewed from the perspective of energy/fuel adequacy. A cumulative price threshold is designed to address short term events/risks. By contrast, the key risk to energy/fuel adequacy is an extended event such as a drought.

G.17 Because these are prolonged events by their nature, any cumulative price threshold would arrest the upward movement in spot prices. The level of the cumulative price threshold would therefore effectively define the end point pricing conditions in an extreme drought. This means that beyond a certain point, spot prices would not change, even if conditions were deteriorating further. This could create incentives for parties to utilise stored energy resources (whether hydro or thermal) once the threshold is reached, even though the true value of the resource may get higher if the drought continues.

G.18 The cumulative price threshold can also affect spot prices at earlier points in a drought sequence. This arises because, during an energy constraint situation, current spot prices will reflect the range of possible future spot price outcomes multiplied by the probability of each of them occurring. A cumulative price threshold could therefore influence:

- the level and timing of discretionary thermal generation;
- the time at which different tranches of price-based demand response will be operating; and
- the likelihood of requiring public conservation campaigns.

G.19 If a cumulative price threshold during drought events was set too low, it would delay the point at which these actions occur, and consequently shorten the elapsed time before rolling outages are required.

G.20 In conclusion, it appears very difficult to apply a single value cumulative price threshold in New Zealand that mitigates short term capacity risk without also undermining incentives for management of dry year energy risk. In principle, this could be addressed by adopting a hybrid cumulative price threshold that has a value of (say) $168,000[193] to address shorter term events, but increasing this value or suspending the mechanism during droughts. However, the borderline between these states is not entirely clear cut and doubts may arise about how it would be applied in practice.

G.21 More generally, a cumulative price threshold would introduce other implementation issues. For example, it would (presumably) apply on the same geographic basis as scarcity pricing regions (i.e. islands as set out in Section 5.4). By implication, if the rolling average price in

[192] In particular, this has considered a threshold set at $1,000/MWh (10% of the scarcity price value for emergency load shedding), and measured over a rolling 7 day period.

[193] Equivalent to $1,000/MWh sustained over 7 days.

one island reached the threshold level, then a lower cap would apply to prices/offers in that island. However, the lower cap would not apply to offers or prices in the other island. This raises the question of how to deal with inter-island flows. In theory, situations could arise where power is flowing from the island with higher prices (where a cumulative threshold has not been triggered) to the one with lower prices (where the threshold was triggered). This type of situation arises in the Australian market, and mechanisms are required to ensure revenue adequacy for settlement purposes.

G.22 In conclusion, while a cumulative price threshold has some attraction, it is difficult to design a simple mechanism that would usefully moderate risk without also undermining incentives for management of dry year risk. For this reason, the permanent introduction of a cumulative price threshold would pose some challenges in the New Zealand system. That said, there may be merit in adopting a mechanism of this type as a transitional measure. This would allow for the introduction of scarcity pricing, but moderate the initial impact to allow parties to gain experience with arrangements and make necessary changes to their plans. This in turn could increase the overall credibility and durability of the scarcity pricing arrangements.