Consultation Paper

Scarcity pricing and related measures - proposed amendments to the Code

Prepared by the Electricity Authority
13 July 2011

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Executive summary

1. The Authority is progressing a number of priority projects intended to improve the performance of the electricity market. The proposed introduction of scarcity pricing (and related changes) is one of these projects, and is focussed on improving security of supply incentives by preventing prices falling when demand is involuntarily curtailed to balance available supply. Scarcity pricing is also one of the specific new matters to be covered in the Electricity Industry Participation Code (the 'Code') by 1 November 2011, as required by section 42(2) of the Electricity Industry Act 2010.

Changes from initial proposal

2. The Authority released a consultation paper[1] on a proposed scarcity pricing design and associated disclosure mechanism in March 2011. A number of modifications have been made to those proposals in light of issues raised in submissions, feedback from the Scarcity Pricing Forum and Scarcity Pricing Technical Group, and further analysis by the Authority.

3. The main changes are to narrow the scope of emergency events covered by scarcity pricing, and to alter the form of application from a price floor to a combined price floor and cap in load shedding situations. The reasons for this are set out in Section 2. In essence, the changes should provide clearer signals for participants, and help to ensure that scarcity pricing will be durable over time.

4. Changes have also been made to the proposed disclosure mechanism discussed in the previous consultation paper. This mechanism is now referred to as the 'stress testing regime'. The key substantive changes are to simplify the required disclosures, and modify the regime to avoid public release of identifiable participant information. Instead, a summary report will be published which does not identify individual parties.

5. Table 1 summarises the initial and revised proposals.

[1] See "Consultation Paper – Proposed Design", 28 March 2011, *Electricity Authority.* This document is also referred to as the "previous consultation paper".

Table 1: Initial and revised proposals – key elements

Item	Initial proposal (March 2011)	Revised 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	Has been retained but simplified
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)	Apply scarcity price as a *price floor and cap* rather than a *price floor* in emergency load shedding. The proposed floor value is $10,000/MWh. The proposed cap value is either: • $10,000/MWh (i.e. same as floor); or • $20,000/MWh.
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)	Not included in this proposal
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)	Not included in this proposal
Disclosure mechanism	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	This proposal has been changed to a stress testing regime and results will not be disclosed in a manner that would identify individual parties

Transition	Disclosure mechanism in place by winter 2012. Scarcity pricing commences when Pole 3 is commissioned (expected late 2012)	Stress testing would commence in March 2012 Subject to further discussion with the system operator, scarcity pricing (including changes to pricing in IR shortfalls) would commence on 1 June 2013

Assessment of proposed changes

6. The proposed Code amendments are expected to contribute to meeting the reliability limb of the Authority's statutory objective. This is because there is significant risk that the efficient level of reliability will not be realised.

7. Under current arrangements, the system is expected to provide an inefficient level of reliability over time because spot prices are likely to be suppressed on average during forced load shedding. In addition, some parties have an incentive to talk up supply risks with the objective of accelerating the use of emergency measures (e.g. public conservation campaigns), talking down spot prices, or promoting ad hoc changes to the market. These factors combine to undermine the incentives on parties to prudently manage risks, and for the system to achieve the efficient level of reliability.

8. The proposed Code amendments are intended to directly address these issues. The price formation process during widespread emergency load shedding (island or national) would be changed to provide greater revenue certainty for providers of last resort resources, and more assurance for purchasers that spot prices in emergency load shedding will not settle well above the level expected in a workably competitive market. The proposed stress testing regime would reduce the scope for some parties to 'talk up' security risks to promote ad hoc policy changes or early use of emergency measures such as conservation campaigns. This 'talking up' of risk has a corrosive effect on confidence in electricity market arrangements, and has damaging flow-on consequences for wider investment and growth.

9. The proposed Code amendments are expected to enhance competition for the provision of last resort generation and demand response resources, as potential providers would have more surety about the rewards from entering that market. Moreover, both scarcity pricing and the stress testing regime should increase incentives for consumers and net retailers to hedge with providers of last resort plant, further increasing competition for provision of those resources.

10. The Authority has considered whether scarcity pricing is likely to 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 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 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. It is important to note that the Authority is pursuing other initiatives outside the scarcity pricing arena that have a pro-competitive intent.

11. Consequently, based on present information, it is expected that the proposed changes will contribute to meeting the competition limb of the Authority's statutory objective.

12. In relation to the efficient operation limb of the Authority's statutory objective, the proposed changes are also expected to be positive in overall terms. This is because the changes should provide greater assurance that the efficient level of security and reliability will be provided by the electricity system.

13. The Authority has considered the extent to which expected efficiency gains from the proposed changes will be shared with consumers. The Authority notes that consumers ultimately bear the costs of adverse outcomes under current arrangements in the form of increased risk of load shedding. The proposed changes are designed to address this issue.

14. The Authority has sought to estimate the expected impacts of the proposed changes in quantitative terms. The scarcity pricing proposal is estimated to have economic benefits of approximately $40 million to $138 million in net present value terms. Sensitivity testing indicates that net benefits are still expected, even under a range of plausible downside scenarios.

15. The primary benefit of the stress testing regime is expected to be stronger economic growth due to greater confidence in security of supply, and correcting the perception that New Zealand is unduly vulnerable to supply crises. If this was the only benefit, even an extremely small increase in gross domestic product 1/2000th to 1/5000th of one percent per year would be sufficient for the regime to yield net benefits. Alternatively, if the regime had no impact on business confidence but only increased the expected return period for public conservation campaigns, even an incremental improvement of 6-12 months[2] would be sufficient for the stress testing regime to yield net benefits.

16. In light of these factors, the Authority is proposing to adopt Code amendments to introduce scarcity pricing and the stress testing regime. The proposed form of the Code amendments is set out in Appendix C.

Implementation date

17. The Authority has requested the system operator consider ways to implement the Authority's projects more quickly than currently indicated. The current

[2] Assuming a base line expected return period of 10 years.

indications are that the system operator would implement the scarcity pricing changes by 1 June 2013. A firmer implementation date will be available before the Authority makes final decisions on the scarcity pricing proposal. The Authority is aware of the need to provide sufficient time for parties to adjust their risk positions.

18. In the case of the stress testing regime, it is proposed that it will apply from the second quarter of 2012 (i.e. the first disclosure reports would be required by late March 2012).

Other changes to wholesale market

19. The Authority is progressing a number of other proposed changes to improve the efficiency of the wholesale market which would complement the scarcity pricing and stress testing regime. These include:

- the introduction of a dispatchable demand product – to increase demand responsiveness by providing price certainty for demand-side participants;
- changes to demand-side bidding and forecasting arrangements which should consolidate pre-dispatch price schedules and facilitate greater competition and demand-side response;
- the introduction of inter-island financial transmission rights 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 and the promotion of competition by encouraging new entry into the retail market; and
- encouraging the development of a more liquid energy hedging market.

20. These changes should complement the scarcity pricing and stress testing proposals because they will strengthen competition, facilitate prudent risk management, and increase the scope for demand side participation.

Next steps

21. The Authority seeks views from submitters by 5:00 pm on 26 August 2011 on the issues set out in this paper and the proposed Code amendments. This feedback will be taken into account by the Authority when making decisions on the proposed Code amendments. Final decisions are expected in the third quarter of 2011, so that any resulting Code amendments can be made by 1 November 2011.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
AUFLS	Automatic under frequency load shedding
Code	Electricity Industry Participation Code
DSM	Demand side management participation
FIR	Fast instantaneous reserve
FTR	Financial transmission right
GWAP	Generation weighted average price
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)
MWh	Megawatt hour
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

Contents

1 Introduction and purpose of this paper

1.1 Introduction

22. 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 by preventing prices falling when demand is involuntarily curtailed to balance the available limited supply. Scarcity pricing is also one of the specific new matters to be covered in the Electricity Industry Participation Code (the 'Code') by 1 November 2011, as required by section 42(2) of the Electricity Industry Act 2010.

23. The Authority released a consultation paper on a proposed scarcity pricing design and associated disclosure mechanism in March 2011. A number of modifications have been made to those proposals in light of issues raised in submissions, feedback from the Scarcity Pricing Forum and Scarcity Pricing Technical Group, and further analysis by the Authority.

1.2 Purpose of this paper

24. The purpose of this paper is to consult on proposed Code amendments to introduce scarcity pricing and a stress testing regime.

25. This paper is a regulatory statement in accordance with section 39 of the Act. As such, it sets out a statement of the objectives of the proposed Code amendments, an evaluation of the costs and benefits of the proposed amendments, and an evaluation of alternative means of achieving the objectives.

26. The Authority invites feedback on the proposals discussed in this paper and the draft Code amendments set out in Appendix C. Final decisions are expected in the third quarter of 2011, so that any resulting Code amendments can be made by 1 November 2011 (noting that these proposals would come into force at later dates).

1.3 Submissions

27. 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 and Related Measures – Proposed Amendments to Code" in the subject line.

28. 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

29. Submissions should be received by 5:00 pm on 26 August 2011. Please note that late submissions are unlikely to be considered.

30. 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.

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

32. 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.

2 Problem definition

Section summary

- The previous consultation paper noted the likelihood of spot price suppression if non-price rationing mechanisms are used during supply emergencies. This suppression would reduce the incentive for voluntary demand-side response and generation, and ultimately undermine security of supply. The previous paper also noted that participants can have an incentive to talk up security risks, to bring forward the use of public conservation campaigns, or promote ad hoc policy changes to reduce spot prices.
- Some submitters endorsed this problem definition, but others questioned the extent of problems with current arrangements based on:
  - a view that the latest system operator Annual Security Assessment reports no risks for the next few years;
  - recently announced projects which could indicate adequate investment incentives; and
  - a posited change in generator offer behaviour that could remove concerns about price suppression in forced load shedding.
- The Authority has considered these points. It does not believe the Annual Security Assessment should be interpreted as an ‘all-clear’. It notes that the system operator supports the introduction of scarcity pricing and has stated “without a change to the market design, security of supply cannot be expected to improve”.
- In respect of recent investment announcements, it is difficult to know the extent to which investors are anticipating the adoption of scarcity pricing. However, its potential introduction has been foreshadowed for two years. At least one investor has informally indicated that its investment case factored in an expectation that scarcity pricing would apply.
- Finally, some submitters posited a change in offer behaviour, such that generators are more likely to offer at prices which approximate the value of lost load in tight system conditions. They believed this would remove the need for an administered scarcity price. It is not clear that a posited change in offer behaviour should be relied upon as a firm guide as to what will occur in supply emergencies. Furthermore, providers of last resort resource (demand-side response and generation) would still face revenue uncertainty because very high prices (even for brief periods) may be challenged *after the event*. Equally important, purchasers want to ensure that spot prices in emergency load shedding will not settle well above the level expected in a workably competitive market.
- In summary, none of the issues raised in submissions has fundamentally altered the view around the risk of spot price suppression when non-price rationing is applied. However, submissions have highlighted the common interest among purchasers and suppliers in reducing the uncertainty around spot price outcomes during a supply emergency. This has implications for the form of proposed Code amendments as discussed later in this paper.

2.1 Incentives during supply emergencies

33. The previous consultation paper described the Authority's concerns with existing arrangements. In particular, it noted that:

- there is potential for spot price suppression during supply emergencies if non-price rationing mechanisms are used, such as forced load shedding[3];
- spot price suppression reduces the incentive for providing voluntary demand-side response in supply emergencies, increasing the level of reliance on forced load shedding (with higher economic costs);
- suppression of spot prices has adverse flow-on effects for security of supply, by reducing the incentives to prudently manage risks, manage fuel stocks, commit units for operation, and invest in greater levels of demand-response or generation; and
- net buyers[4] in the spot market could have a financial incentive to 'talk up' security risks to persuade the media, consumers and policy makers that policy changes or non-price rationing (especially for public conservation campaigns) is required. Parties can make very damaging claims about market competitiveness during periods of system stress in an effort to reduce spot prices. The atmosphere of crisis can make it harder to properly assess the merits of these claims. This in turn undermines market resilience, hinders wider productive investment and increases the risk of ad hoc intervention.

34. Submitters had differing views about the extent of problems with current arrangements. Some endorsed the view in the consultation paper, but others considered current arrangements to be satisfactory. The key reasons for the latter position were perceptions that:

- the latest system operator Annual Security Assessment reports no risks for the next few years;
- recent investments indicate that current arrangements are adequate; and
- a change in offer behaviour (a posited move away from the "SRMC linked paradigm") may have removed concerns about price suppression with current arrangements.

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[3] The previous consultation paper also noted that this could have the flow-on effect of encouraging generators with limited fuel stocks to suppress short-term spot prices (and reduce conservation) since they would face a lower spot price risk in any subsequent load shedding.

[4] 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. It can also include end users with direct exposure to spot prices through their retail supply contracts.

35. Each of these is commented upon below.

2.1.1 Annual Security Assessment

36. The latest Annual Security Assessment should not be interpreted as an all-clear on security of supply. First, it focuses on investment adequacy, and does not consider whether plant will be physically fuelled/running when required. This has been an area of historic concern and scarcity pricing would be expected to strengthen incentives in this area.

37. Second, the projections of investment adequacy are based on assumptions that are subject to revision. The results can be very sensitive to changes in these assumptions. For example, a change of one year in plant commissioning for some investments can materially alter the outlook. Furthermore, as noted in the next section, existing plans for new investment/plant retention may in part reflect expectations that some form of scarcity price mechanism will be adopted. The assessments therefore provide a guide rather than an assurance about future outcomes.

38. Finally, in commenting on the previous consultation paper, the system operator itself stated: "the underlying problem has been recognised, refined over at least two years, and documented. Without a change to the market design, security of supply cannot be expected to improve".

2.1.2 Continuing new investment

39. The fact that parties are committing to new investments (e.g. Contact's 200MW peakers in Taranaki or TrustPower's forthcoming investment at Marsden Point) was cited in submissions as evidence that no change is required.

40. It is difficult to know the extent to which recent investments anticipate the adoption of a scarcity pricing regime, given that this possibility has been mooted since 2009. However, at least one investor has informally indicated that its investment case was based on the expectation that some form of scarcity pricing for capacity shortages would apply in the future.

41. The existence of recent investment commitments cannot therefore be treated as evidence that no problem exists.

2.1.3 Posited change in offer behaviour

42. Some submitters queried whether supply-side offer behaviour altered in 2011 such that generators are more likely to offer at prices which approximate the value of lost load in tight system conditions. They argued that such behaviour would remove the need for an administered scarcity price.

43. It is clearly difficult to form a definitive view on this issue, because participant behaviour is subject to a wide range of influences and can change through time. At the very least, it is uncertain whether any posited change in offer

behaviour could be relied upon as a firm guide as to what will occur in supply emergencies.

44. As noted in the previous consultation paper, there is potential for differing views on the boundary between acceptable and unacceptable offer prices during a supply emergency. Arguably, 'technical' price suppression should not be an issue during load shedding because supply and demand-side[5] offers are uncapped. However, spot prices may need to reach very high levels to justify investment in resources that are called upon very infrequently. Introducing scarcity prices for emergency load shedding would provide a clear signal to providers of last resort resources that very high prices are acceptable in supply shortage situations.

45. Equally important, purchasers are concerned about the prospect of paying an unduly high price in an emergency, knowing that competition is likely to be more limited when the system is under stress. Purchasers want to be assured that spot prices in emergency load shedding will not settle well above the level expected in a workably competitive market.

2.1.4 Conclusion

46. In summary, none of the issues raised in submissions has fundamentally altered the view around the risk of spot price suppression. In particular, where involuntary demand reduction measures are applied in a supply emergency, there is a risk of price suppression, and consequent weakening of incentives to prudently manage risks.

47. Submissions have highlighted the common interest in reducing the uncertainty around spot price outcomes during a supply emergency:

- last resort resource providers would have greater assurance about expected revenues; and
- consumers would have more assurance that prices are not beyond what might be expected in a workably competitive market.

48. This has implications for the design of scarcity pricing arrangements to apply in a shortage situation, as discussed later in this paper.

Question 1: Do you agree with the problem definition?

5 Demand-side offers refers to interruptible load (which can set reserve and hence energy prices). It would also include the proposed dispatchable demand product (which is currently being consulted upon by the Authority).

3 Scarcity pricing changes – revised proposal

Section summary

- The Authority has made significant modifications to the scarcity pricing design and associated disclosure mechanism contained in the consultation paper issued in March 2011. The modifications have been made in light of issues raised in submissions, feedback from the Scarcity Pricing Forum and Scarcity Pricing Technical Group, and further analysis by the Authority.
- The Authority no longer proposes to apply scarcity pricing during public conservation campaigns or rolling outage load shedding. Instead, scarcity pricing would be confined to emergency load shedding. The scarcity price mechanism has been altered from a price floor to a price floor and cap mechanism. Other elements have been retained largely unchanged (for example, the stop-loss mechanism and modifications to final pricing where an infeasible solution arises due to an IR shortfall). The changes noted above should provide clearer signals for participants about price outcomes in emergency load shedding, and help to ensure that scarcity pricing will be durable over time.
- Changes have also been made to the proposed disclosure mechanism discussed in the previous consultation paper. This mechanism is now referred to as the 'stress testing regime'. The key substantive changes are to simplify the required disclosures, and modify the regime to avoid public release of identifiable participant information. Instead, a summary report will be published which does not identify individual parties. The Authority proposes to introduce the stress testing regime from March 2012.

3.1 Scope of scarcity pricing

49. The Authority's previous consultation paper on his matter noted that four distinct types of supply emergency can arise, as shown in Table 2.

Table 2: Types of supply emergency and non-price response mechanisms

Shortage of voluntary demand response or generation in real time	**Instantaneous reserve shortfall** (less severe)	⇨	**Emergency load shedding** (more severe)
Expected shortage of voluntary demand response or generation over coming periods	**Public conservation campaign** (less severe)	⇨	**Rolling outage load shedding** (more severe)

Declining frequency of occurrence →

50. Separate mechanisms were proposed to deal with each situation:

    (a) a modification to spot pricing during instantaneous reserve (IR) shortfalls (fine tuning of changes introduced in mid-2010);

    (b) a $10,000/MWh spot price floor during emergency load shedding;

    (c) a $500/MWh spot price floor during public conservation campaigns; and

    (d) a $3,000/MWh spot price floor during rolling outage load shedding.

51. After considering issues raised by submitters and undertaking further analysis, the Authority intends to narrow the mechanisms to focus on IR shortfalls and emergency load shedding[6] (i.e. the short-term capacity shortage situations). It no longer proposes to introduce price floors for public conservation campaigns or rolling outage load shedding.

52. The reasons for narrowing the proposed scarcity pricing measures are:

    - the establishment of a market failure is clearest for short-term capacity shortfalls. Under current arrangements, no explicit account is taken in final pricing of the costs imposed on electricity users if involuntary load

[6] In this paper, “emergency load shedding” refers to disconnection instructions issued by the system operator pursuant to Part 8 of the Code. These instructions would necessarily be based on limited information and would focus on achieving a supply-demand balance in the short term. The system operator may also instruct load shedding under Part 9 of the Code (“Rolling Outages”) where an event is expected to be extended (whether due to transmission, fuel, or generation capacity issues). To implement rolling outages, the system operator must (after consultation with the Electricity Authority) issue a supply shortage declaration. It must then determine the allocation of savings targets (again after consultation with the Electricity Authority) in accordance with the Code and relevant plans, and issue curtailment directions to participants which provide forward notice (if practicable).

shedding is invoked. While forced load shedding would also arise with rolling outages, the provision of advance notice should give greater scope for parties to establish mutually beneficial commercial arrangements (e.g. demand buybacks). There is also increased scope for demand-side participants to react and voluntarily reduce their demand. Lastly, in the case of public conservation campaigns, no forced load reduction is imposed on electricity users[7];

- there is international precedent for applying scarcity prices for short-term emergency load shedding. For example, the approach has been adopted for a number of years in Australia[8], Singapore and Texas. The Authority is not aware of any overseas market that applies a scarcity price floor for energy shortages per se[9]. The absence of international precedent means that there is greater risk of unanticipated effects arising with an energy-related scarcity price mechanism (for example, it could create a perverse incentive for thermal generators to withhold supply to hasten the triggering of the floor);

- the implementation issues are more challenging for energy related scarcity pricing than for capacity shortages. In the former case, it would be necessary to define scarcity values which reflect the *contingent risk* of emergency load shedding, recognising that there is no actual supply deficiency in the current period[10]. However, the marginal value of electricity is likely to vary during the course of an energy shortage given its sustained nature. A price floor for a *sustained* period would be very intrusive to market operations if set too high and ineffective if set too low. By contrast, emergency load shedding events are relatively short in duration. This makes it less difficult to develop a scarcity price approximation which reflects expected conditions in such events;

- price floors during extended energy shortages will only be effective (i.e. alter risk management behaviour) if they are perceived as durable. However, their durability is doubtful if they are vulnerable to being overturned (e.g. due to criticism that they are too high and are responsible for lost export orders, supplier failures etc). Price floors during energy shortages are expected to be used very infrequently, making it difficult to establish policy credibility ahead of time;

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[7] Although there may still be a divergence between spot prices and the cost imposed by official conservation campaigns for the reasons set out in Section 5.5 of “Consultation Paper : Scarcity Pricing – Proposed Design”, *Electricity Authority*, March 2011.

[8] In the National Electricity Market covering the five states and capital territory of eastern Australia.

[9] This refers to situations where forced load shedding is instructed even though there is sufficient resource available to meet load in the *current* period, but insufficient resource to meet forecast demand over a *longer p*eriod. It is important to note that most electricity markets do not face any appreciable risk from this type of shortfall. New Zealand is relatively unusual in this respect.

[10] Rather, the concern is that widespread forced load shedding may be required in subsequent periods.

- a price floor during public conservation campaigns appears unlikely to fully address one of the key concerns with current arrangements, which is the lobbying and ‘talking up’ of security concerns that occurs *in advance* of such campaigns. This is often directed at accelerating the use of public conservation campaigns, or promoting ad hoc interventions to artificially lower spot prices. In these situations, parties exposed to spot prices will often make very damaging claims about the effectiveness of the electricity market (e.g. that hedges were not available on reasonable terms and/or that spot prices are not competitively determined), which can be difficult to properly assess in a crisis atmosphere. A price floor introduced during public conservation campaigns could simply shift the focus of lobbying to the price floor and to the regulatory regime more generally, and would not reduce the incentive to lobby or make it easier to assess the effectiveness of the market; and
- concerns about energy security have been addressed to some extent by other measures. In particular:
  - o the adoption of clear pre-defined triggers for starting and stopping public conservation campaigns should narrow the scope of lobbying in an energy shortage, or in the lead up to such an event[11].
  - o the introduction of the customer compensation scheme should significantly reduce the financial incentive that electricity retailers would otherwise have to call for public conservation campaigns;
  - o the virtual and physical asset swaps between SOE generators should lessen the energy scarcity risks associated with the decisions made by both companies; and
  - o the proposal to adopt scarcity pricing for emergency load shedding events should have a ‘signalling effect’ that flows into the energy security time domain.

53. However, the Authority believes that energy security, and perceptions about energy security, remains an important issue for New Zealand, and that past performance is widely perceived as inadequate (as evidenced by the use of public conservation campaigns three times in the last decade and frequent claims that a market-based approach is ineffective). A ‘no change’ stance in the energy context is therefore not acceptable. For this reason, the Authority proposes to introduce a stress testing regime that would require parties to

[11] The Authority has recently determined that the trigger point for starting a public conservation campaign will be hydro storage falling below the 10% 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 trigger points. Furthermore, the calculation of the trigger conditions is subject to a number of areas of judgement by the system operator. For these reasons, the incentive on some participants to talk up the level of supply risk has not been entirely eliminated.

apply a set of standard stress tests to their electricity market positions. The results of applying these tests would be reported to the Authority on a confidential basis.

54. Participants would retain sole responsibility for managing their risk exposures. However, the fact that they must report the impact of the standard stress tests to the Authority is expected to alter their behaviour as the Authority will be better positioned to deflect opportunistic lobbying against the spot market, and in particular lobbying for initiatives to suppress spot prices. It would also place the Authority in a more informed position to identify legitimate concerns with market performance. The form of the proposed regime is described further in Section 5.

Question 2: Do you agree that the proposed narrowing of scarcity pricing (to be applied for short-term emergencies and not for extended shortages) would be more consistent with the Authority's statutory objective?

3.2 Form of scarcity price measure in emergency load shedding

55. The Authority had proposed to introduce a $10,000/MWh price floor for emergency load shedding.

56. A number of submitters noted that a price floor would address concerns about price suppression, but would not address the potential for spot prices in emergency load shedding to settle well above the level expected in a workably competitive market. These submitters proposed that scarcity pricing be applied as an administered price *level*[12] rather than a *floor*. This approach would effectively mean that spot prices would be subject to a floor and cap (set at the same level) during a scarcity pricing event.

57. It was argued that applying scarcity pricing as an administered value would be consistent with the notion that emergency load curtailment is 'offered' into the market as a standing bid, and reduce the likelihood of 'overshooting' in signalling terms. This in turn would reduce the risk that scarcity pricing will encourage inefficiently high levels of security, and contribute to policy durability.

58. Some submitters went further and argued that a price capping mechanism should apply at all times. Other submitters felt that generalised price capping mechanisms were not required, or that their relative merits should be considered in a broader context (i.e. not as part of proposed scarcity pricing changes).

[12] Subject to any adjustment to reflect transmission losses or other nodal price differences. These issues are discussed further in section 4.5. This caveat to the term "level" applies throughout this paper.

59. As noted in the previous consultation paper, price capping mechanisms are not straightforward to implement and carry a significant risk of unintended consequences. In particular, there is the potential for dampening of incentives for parties to proactively manage risks.

60. After weighing these considerations, the Authority is proposing to proceed as follows:

- scarcity price event – apply scarcity pricing as a price floor and a price cap[13], rather than simply a floor; and
- general market – not introduce a generalised price cap. The Authority believes that in the longer term competitive forces, such as the entry of peaking plant or the prospect of such entry, should place sufficient competitive discipline on pricing behaviour in periods where there is sufficient generation to meet demand.

61. This approach is intended to provide greater certainty about prices during a widespread load shedding event, which should be beneficial for both purchasers and suppliers.

Question 3: Do you agree that scarcity pricing should be applied as a price floor and cap, rather than simply a price floor during emergency load shedding?

3.3 Stop-loss mechanism

62. The previous consultation paper canvassed the possibility of introducing a transitional 'stop-loss' mechanism to place a boundary on cumulative spot price risk (as distinct from price risk in a single trading period as discussed in the previous section).

63. That paper noted that a stop-loss mechanism could be specified in terms of a cumulative price threshold (i.e. a price/offer cap that operates temporarily if the market has had sustained high prices), or a maximum duration for which scarcity pricing could be applied.

64. The paper also noted that such mechanisms would increase the complexity of possible changes to pricing arrangements, and that there would be a risk of unintended consequences (especially if cumulative limits on prices are applied). In light of these factors, the paper proposed that any price/offer capping mechanism should not be introduced on a permanent basis, but could be a possible transitional measure.

65. There was significant (though not unanimous) support for a stop-loss mechanism by both demand and supply-side submitters as a tool to improve policy durability. It was felt that a mechanism of this type could reduce the risk

[13] As discussed in Section 4.5.1 on implementation issues, a common value could be applied for the floor and the cap, or separate values could be applied.

of contagion effects[14], and provide more scope for parties to put in place orderly commercial arrangements during a supply emergency if required. Submissions supporting this type of mechanism also generally favoured its adoption as a standing feature, i.e. it would operate at all times not just when scarcity pricing is being applied.

66. Submissions that opposed a stop-loss mechanism suggested that it:

- was unnecessary (because they opposed scarcity pricing), or
- would mute the incentives promoted by the scarcity price, or
- should be considered as a separate issue outside the context of scarcity pricing.

67. The Authority sees merit in adopting a stop-loss mechanism for scarcity pricing, but it is not persuaded that a general stop-loss mechanism should apply due to the potential for unintended adverse consequences.

68. The Authority proposes that the scarcity pricing stop-loss mechanism would apply at least until the first review date for the scarcity pricing parameters (see Section 3.8). Further detail on the how the proposed stop-loss mechanism would be implemented is set out in Section 4.5.6.

Question 4: Do you agree that scarcity pricing should include a stop-loss mechanism, at least on a transitional basis?

3.4 Forced demand curtailment in AUFLS event

69. The previous consultation paper noted that forced load shedding could occur through triggering of automatic under frequency load shedding (AUFLS)[15] relays rather than an instruction from the system operator. The paper noted that because AUFLS can only curtail demand in sizeable blocks (i.e. currently 16% or 32% of island load), there is a high likelihood that AUFLS would cut more load than is strictly required, and some operating generation would also be required to reduce output to achieve system balance.

70. As a result, there could be ‘excess’ demand curtailment and further price-based load reduction could be unhelpful in seeking to stabilise the system. In addition, wholesale market participants would have little or no control over which load and generation is tripped off in an AUFLS event. This would make it difficult for them to predict and manage their positions (for example parties that were prudently hedged might be exposed if their generation was tripped off in an AUFLS event).

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14 For example, multiple purchaser insolvencies which trigger wider problems for supplier counterparties.

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

71. In light of these factors, the previous consultation paper proposed that AUFLS would not trigger scarcity pricing. The paper noted that this is the approach which applies in the Australian National Electricity Market.

72. There was broad support for this proposed approach among submitters[16]. The key reservation raised was that a scarcity price signal could be useful once 'excess' demand curtailment had been restored, and the system is transitioning out of an AUFLS event.

73. After considering submissions, the Authority intends to retain the initial proposal that AUFLS will not trigger scarcity pricing. However, it acknowledges that a scarcity pricing signal would be beneficial if load restrictions are in place once all offered generation has been dispatched (and 'excess' demand curtailment restored). The proposed implementation of scarcity pricing discussed in Section 4.2 takes this into account.

Question 5: Do you agree that scarcity pricing should not apply for AUFLS per se?

3.5 Geographic extent of shortage to trigger scarcity pricing

74. The previous consultation paper noted that scarcity prices could be applied to load shedding events affecting single nodes, or be limited to events that only affect wider areas (e.g. an island, or a national threshold).

75. The paper noted that events of a more localised nature are likely to be primarily driven by transmission-related issues[17]. It was not clear that applying a scarcity price signal for more localised events would improve economic efficiency, given that transmission decision-makers[18] are not currently exposed to the nodal price consequences of these choices. The paper also noted that the choice of geographic threshold would have an impact on locational price risk, and that a nodal threshold could significantly increase the level of intra-island locational price risk.

76. The Authority proposed that a minimum geographic threshold of an *island* shortage event be adopted at the outset. This was based on a judgement that applying scarcity prices for nodal or regional curtailment events carried a higher risk of unintended outcomes than if scarcity pricing is applied for national or island level shortages. The Authority put significant weight on this issue, because it is concerned to promote policy sustainability if scarcity pricing is introduced.

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16 However, some submitters that opposed scarcity pricing offered no view on this issue.

17 See Appendix D of previous consultation paper for an analysis of scarcity events between 2003 and 2010.

18 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.

77. Of the submitters that expressed a preference on the minimum geographic threshold, most supported a threshold that was higher than the nodal level[19]. In general, the island level appeared to attract the greatest support, although there was also some interest in a national threshold, or a lower regional threshold.

78. After considering submissions, the Authority intends to retain the proposed island-level geographic threshold. In the Authority's view, this threshold provides an appropriate balance between providing the desired signals for generation and demand-response to avert widespread shortages, while narrowing the scope for unintended adverse effects. The Authority intends to review this threshold over time, and lower it (i.e. apply to a more localised area) if this is judged to be consistent with the Authority's statutory objective.

Question 6: Do you agree with the proposed geographic threshold for initial application of scarcity pricing, and if not why?

3.6 Infeasibility following shortfall in instantaneous reserves

79. The previous consultation paper noted that changes introduced in mid-2010 by the Electricity Commission largely addressed the potential for unintended spot price suppression to arise during IR shortfalls.

80. However, the paper also noted that under these modified procedures, there is potential 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 such an outcome might be mathematically 'correct', uncertainties around some input parameters (e.g. due to meter error factors) meant that the resulting prices could have doubtful economic integrity.

81. In light of these factors, the Authority proposed that an additional procedure would be applied in final pricing when IR shortfalls occur in dispatch and an infeasible solution arises in final pricing. The additional procedure would introduce a 'virtual' provider with an offer price set at the greater of the highest energy or reserve offer, or a value from a pre-defined IR shortage function. The inclusion of the virtual provider would reduce the scope for final prices to settle at levels that are many multiples of the highest offer or energy price.

82. Submissions on the proposal fell into two broad camps. Some submitters considered that there was no clear need for change, or that the issue should be addressed outside the context of scarcity pricing because it was not a

[19] One submitter supported the nodal threshold for all load shedding, and another supported its use for capacity shortages, but preferred an island threshold for energy shortages. It is also important to note that some submitters that opposed scarcity pricing offered no view on the preferred geographic threshold.

section 42[20] matter. The balance of submitters considered that there is a need to address the potential for extremely high prices to arise if an IR shortfall triggers the infeasibility resolution procedures. These submitters generally supported the proposed modification to pricing processes.

83. In relation to the need for change, it would be possible to wait until a problem has been 'demonstrated' – i.e. instances of very high prices after infeasibility resolution caused by IR shortfalls. However, it is not clear that addressing the issue ex-post would be preferable to an ex-ante change. The Authority would generally prefer to provide a framework that is clear and let participants make decisions in light of that framework. This is expected to promote certainty and policy credibility over time, and be in the long term interests of consumers.

84. Furthermore, the Authority believes that sufficient analysis has been carried out to establish that the risk is material. 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 somewhat higher, and existing pricing processes were applied. This final price would have been more than forty times the value of the highest generator offer in the supply stack in that period ($1,000/MWh)[21]. Lastly, the Authority acknowledges that this issue is not a section 42 matter, per se. However, the Authority would prefer to address the issue at this time because it falls within the broader category of how spot prices are determined during emergency conditions.

85. Having considered submissions, the Authority remains of the view that a modification to existing procedures is desirable when an IR shortfall triggers an infeasible solution in final pricing. However, in light of submissions and further analysis (including with the system operator), the Authority intends to simplify the modification slightly from that proposed in the previous consultation paper. The details of this change are set out in section 4.6 on implementation issues.

Question 7: Do you agree that an amendment should be made to final pricing processes when an infeasible solution arises following an IR shortfall?

3.7 Implementation timetable

86. The previous consultation paper set out a range of transition options. While no single preference emerged from submitters, a number of parties noted that it would be desirable to provide some lead time, and suggested that implementation occur once Pole 3 of the HVDC is commissioned (which is expected to be late 2012).

87. This would provide participants with around a year to adjust their plans between the time that Code amendments are made (November 2011) and

20 That is, a matter covered by section 42 of the Electricity Industry Act 2010.

21 See Appendix B of previous consultation paper for more detail.

when they take effect (late 2012). In subsequent discussion within the Scarcity Pricing Technical Group, it was noted that the Pole 3 commissioning date is not certain. A 'floating' implementation date would make it more difficult for market participants to plan for the introduction of scarcity pricing, and make any necessary changes to their risk positions.

88. In light of these factors, the current proposal is that scarcity pricing would apply from 1 June 2013. A firmer implementation date will be available before the Authority makes final decisions on the scarcity pricing proposal. The Authority is aware of the need to provide sufficient time for parties to adjust their risk positions.

89. A shorter implementation timetable is proposed for the stress testing regime. This reflects the expectation that market participants already have procedures in place to measure their exposure to spot price risk as part of their own internal governance arrangements. It should therefore be relatively straightforward for them to apply pre-defined stress tests to their position and report the results to the Authority.

90. It is proposed that the stress testing regime will apply from the second quarter of 2012 (i.e. the first disclosure reports will be required by 31 March 2012).

Question 8: Do you agree with the proposed implementation timetable?

3.8 Review provisions for scarcity pricing parameters

91. The previous consultation paper noted that it would be important to periodically review certain aspects of the scarcity pricing regime. It proposed that these reviews be conducted at least every three years and cover:

- the scarcity price floor and cap value(s) to be applied during emergency load shedding;
- the stop-loss limit for applying scarcity pricing; and
- any other issue notified by the Authority at the time the review commences.

92. The previous paper proposed that at least 12 months notice would be provided before any change flowing from a programmed review would take effect, unless a change is necessary to address an urgent issue. This was designed to assist parties to adjust their plans and/or risk management positions, and reduce the risk of high prices arising from weak competitive pressures.

93. Submitters generally supported the proposal to undertake periodic reviews of scarcity pricing parameters. Some submitters preferred a longer review cycle (e.g. five years) or lead time (e.g. two years) before changes could take effect. Other submitters felt that the review scope should extend beyond the key parameters for scarcity pricing, and consider the whole package of changes.

94. After reviewing these submissions, the Authority considers extending the review period would increase the risk that scarcity price parameters become out of date. In this context, the Authority notes that the Australian NEM operates on a two year review cycle.

95. Likewise, the Authority does not believe that extending the lead time for implementing changes from one to two years would be appropriate. When allowance is made for the time needed to undertake a review and make any subsequent Code amendments, 2-3 years could elapse before a change is adopted to address an identified problem.

96. In respect of the ability to undertake a wider review of scarcity pricing, the Authority notes that it has powers to amend the Code at any time. A programmed review of the scarcity pricing provisions would not preclude the Authority from making amendments to the Code at any other time if they were considered to be consistent with the Authority's statutory objective.

97. The key purpose in conducting *programmed* reviews is to ensure that *specific scarcity pricing parameters* will be considered on a periodic basis. The Authority wishes to ensure that this review process is well understood by participants, as this should help to promote policy sustainability.

98. In light of these factors, the Authority proposes to commence the first programmed review of scarcity pricing parameters in mid-2014. Assuming it takes six months to complete, any consequent change would be signalled at the beginning of 2015. This timetable would:

    - allow the review to draw on experience gained in the first 12-18 months of 'live' operation of scarcity pricing; and
    - mean the first opportunity to 'refresh' scarcity pricing parameters will be early 2015, which will be approximately four years after the values were established[22].

99. The Authority may also conduct an 'interim' review in an exceptional circumstance, but would generally prefer to limit any changes to the cycle of programmed reviews.

Question 9: What is your view of the proposed review provisions for key scarcity pricing parameters?

[22] If the date of the first programmed review were further extended, it may be desirable to adjust scarcity price values to maintain their value in real terms. For example, 3% inflation over five years would erode the scarcity price value by almost 14% in real terms.

4 Scarcity pricing – implementation issues

Section summary

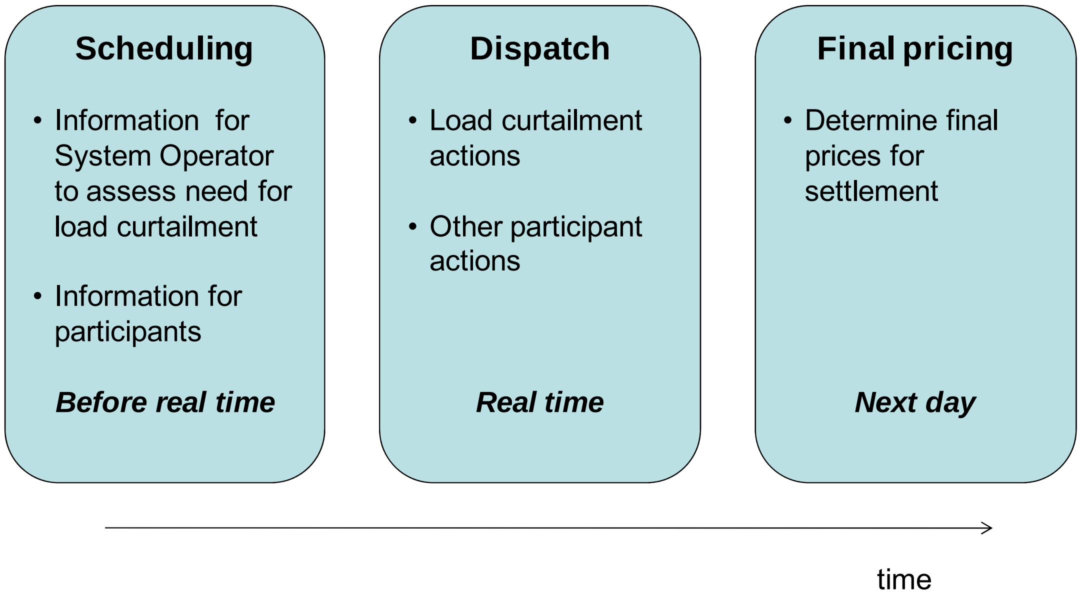
- Participants should receive advance notice of scarcity pricing being applied wherever this is feasible. This would help to ensure that lower cost alternatives to forced load shedding are used to the extent practicable. In addition, the tests for applying scarcity pricing in final pricing should be clear, replicable and consistent with the intended design.
- Accordingly, it is proposed that:
  - scarcity pricing will only be applied in final pricing if the system operator has first issued a national or island shortage declaration;
  - such declarations can only be made if load shedding is invoked, and the underlying shortage is expected to affect the whole of one or both islands; and
  - additional information will be provided in pre-dispatch and real time schedules to assist participants to gauge the likelihood of scarcity pricing being applied in final prices.
- If a national or island shortage declaration is in force at the beginning of a trading period, final prices in the relevant island(s) will be subject to a scarcity price adjustment. Two alternative adjustment processes are being considered:
  - scaling all energy and reserve prices in the relevant island(s) by the factor needed to bring the generation weighted average price (GWAP) to the scarcity price floor/cap[23] value; or
  - setting all generation prices in the relevant island(s) to the scarcity price floor/cap value, and setting corresponding purchase prices to the same value plus an uplift factor to reflect average transmission losses.
- In both cases (and subject to conditions set out in Section 4.5.4) the adjusted final prices would apply for settlement purposes and no separate constrained on payments would be made.
- A stop-loss mechanism would limit the application of scarcity pricing beyond a pre-defined threshold in any rolling seven day period. If the threshold has been reached, no scarcity price adjustment (upwards or downwards) would apply to final prices in the relevant trading period.

[23] The Authority is considering whether the price floor/cap mechanism should use a common value or have two separate values. This is discussed in Section 4.5.1.

4.1 Implementation objectives

100. This section describes the intended approach to implementing scarcity pricing within the system used for scheduling, dispatch and pricing (referred to as the Market Clearing Engine or 'MCE' for short). The MCE operates across three different timeframes as shown in Figure 1.

Figure 1: Timeframes covered by Market Clearing Engine



101. The implementation of scarcity pricing should, as far as practicable, ensure that:

- **scheduling timeframe** - participants are provided with prior warning that scarcity pricing could be applied, where forecast conditions indicate that it would be triggered. This assists participants to undertake voluntary actions ahead of real time, and reduces the likelihood that forced demand curtailment will be required;
- **dispatch timeframe** - participants are notified that scarcity pricing is likely to apply[24] when conditions indicate it has been triggered. This is particularly important where scarcity pricing is applied, due to a supply failure that occurs without warning (and therefore would not be apparent in the prior scheduling timeframe). Providing a clear indicator in real time will strengthen the signals for participants to increase supply/reduce load, which should shorten the period for which forced load shedding is required; and
- **final pricing** – arrangements provide a clear basis for determining whether scarcity pricing applies, and if so, how final prices will be calculated. The

[24] The 'likely' qualification is included because scarcity pricing may not necessarily apply in final prices. For example, it may not operate due to the stop-loss mechanism or differences between real time and final pricing conditions. These issues are discussed later in this section.

scope for subjective judgement should be minimised to reduce the potential for disputes and enhance durability.

102. The proposed form of implementation seeks to attain these objectives in terms of:

(a) trigger for issuing national or island shortage declarations;

(b) trigger for revoking national or island shortage declarations;

(c) scheduling and real-time information;

(d) final pricing;

(e) stop-loss mechanism; and

(f) modifications to final pricing processes for IR shortages.

103. Each of these is discussed below.

4.2 Trigger for issuing national or island shortage declarations

104. The proposed trigger mechanism would determine whether a national or island shortage should be declared by the system operator. This declaration is important because it would:

- provide a ‘flag’ to participants about system conditions at the time the system operator gave the instruction to shed demand; and
- be a pre-condition that must be satisfied before the scarcity pricing process is followed in final pricing.

105. It is proposed that the system operator would make a shortage declaration if:

(a) an instruction to disconnect demand has been issued by the system operator under clause 6(1) or 6(2) of Technical Code B of Schedule 8.3 of the Code; <u>and</u>

(b) the instruction is issued on the basis of information (e.g. a real time dispatch schedule) that indicates:

(i) there are no binding transmission constraints present on the grid in either island, and the HVDC link is in service and unconstrained (for a national shortage declaration); <u>or</u>

(ii) there is a binding transmission constraint on the HVDC link (or it is out of service) and there are no binding transmission constraints on the AC transmission system in the island where load was shed (for an island shortage declaration) [25].

106. Under this approach, load shedding caused solely by the operation of AUFLS equipment will not trigger scarcity pricing, since no load curtailment instruction will have been issued by the system operator[26]. However, if instructed load curtailment is required in the restoration process (indicating a deficit in supply) and other conditions were satisfied, then a shortage declaration would be made. This would have flow-on consequences for the relevant final pricing schedules.

107. It is proposed that clause 7 of Technical Code B of Schedule 8.3 will be amended as set out in Appendix C of this paper to implement the trigger mechanism for declaring a national or island shortage situation.

Question 10: What is your view of the trigger mechanism for declaring a national or island shortage?

4.3 Trigger for revoking national or island shortage declaration

108. In principle, the national or island shortage declaration could be revoked if any of the activation conditions set out in paragraph 105 were no longer satisfied. However, this would be inappropriate because:

(a) the issuing of the load shedding instructions is expected to correct the deficit in generation identified by the system operator. This could mean that scarcity pricing would not be triggered even where it is intended to apply;

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25 A range of simulated shortages were considered to ensure that these tests are workable and likely to be sustainable over time. This analysis indicates that the proposed tests would yield the desired result in most cases. However, it would not trigger scarcity pricing where a spring washer constraint applies within an island, even though in a strict technical sense, demand curtailment would be beneficial at all nodes (although much more so at some nodes compared to others). In practical terms, this technical ‘under-signalling’ appears acceptable, as the application of scarcity pricing during a spring-washer event could yield unintended price outcomes.

Alternative tests were also considered and these introduced a risk of over-signalling (e.g. applying scarcity pricing throughout an island even though the shortage is not island-wide) or were more complex to implement (e.g. requiring additional MCE solves). The tests included:

- re-solving the dispatch solution to determine whether additional load shedding at the lowest price node alters the generation or IR deficit;
- re-solving the dispatch solution without any AC constraints to determine whether deficit generation or IR still occurs without load shedding; and
- determining whether an IR shortfall occurred in the dispatch solution.

26 For the reasons set out in the previous consultation paper, it is not proposed that scarcity pricing would be applied for curtailment initiated through the activation of AUFLS. For more detail, see Section 5.2 of ‘Scarcity Pricing – Proposed Design’, Electricity Authority, March 2011.

(b) widespread load shedding could extend over a number of hours, but conditions may oscillate between island and localised shortages as AC transmission constraints appear and disappear for different trading periods. If the shortage declaration were rescinded at the first appearance of AC constraints, this could mean that subsequent widespread load shedding (without AC constraints) would not trigger scarcity pricing.

109. To address these issues, it is proposed that a national or island shortage declaration will be revoked once all relevant load shedding instructions have been rescinded.

110. Once the system operator publishes the first shortage notice, scarcity pricing pre-conditions are triggered but this does not necessarily mean that scarcity prices will apply. To address the potential for transitory conditions described in 108(b), it is proposed that a separate 'period by period' test for transmission constraints will be applied in final pricing. This will ensure that scarcity prices will not be inappropriately applied in final pricing, even though a shortage declaration was in place during real time (see Section 4.5.4).

111. Other than a notice that the shortage situation is over, it is possible for the system operator to issue further notices of shortage and this may cause the nature of the shortage to change. For instance, a notice that load has been shed in the North Island might be followed by a notice that load has been shed in the South Island. This could cause scarcity prices to be calculated in both islands.

112. It is proposed that all shortage declarations would be notified by the system operator and appear on the wholesale information trading system (WITS).

Question 11: What is your view of the trigger mechanism for revoking shortage declarations?

4.4 Signalling in scheduling and real time

113. To provide participants with a leading indicator of the likelihood of scarcity pricing being applied, it is proposed that the following information (some of which is already published) will be provided in pre-dispatch schedules:

- any expected deficit quantities for energy, fast instantaneous reserve and sustained instantaneous reserve (i.e. to gauge the depth of any shortfall);
- the expected binding transmission security constraints in each island; and
- the expected binding constraints limiting the flow of electricity on the HVDC link, or whether the HVDC link is out of service (i.e. zero flow).

114. This information, combined with the presence of infeasible prices (which are already published) would provide a leading indicator of the likelihood of a shortage declaration being made by the system operator in the upcoming periods.

115. In addition, once a shortage declaration has been made, it is proposed that the declaration status and the information listed in paragraph 113 would be made available to the Wholesale Information Trading System (WITS) in all subsequent real-time dispatch schedules for the relevant island(s) until load has been fully restored and the declaration revoked.

116. It is not currently proposed that the scheduling time or real time dispatch schedules would incorporate scarcity prices per se. The schedules would instead indicate forecast prices based on constraint violation penalties - \$100,000/MWh for fast instantaneous reserve (FIR) or sustained instantaneous reserve (SIR), and \$500,000 for energy.

117. Similarly, if there is a reserve (FIR or SIR) shortage in a scheduling time or real time dispatch schedule (without an associated demand curtailment instruction or demand curtailment being in effect), then a reserve shortage indicator would be provided to market participants.

118. The intention of these indicators is to provide participants with information on the risk of island or nationwide shortages, and associated likelihood of scarcity pricing. These indicators should be useful when a situation is emerging over a number of trading periods or after one has already occurred.

119. The indicators would not provide any direct information on the likelihood of scarcity pricing being invoked due to causes which cannot be forecast (e.g. sudden asset failures etc). However, the potential vulnerability of the system to such failures can be assessed (at least to a degree) through existing indicators such as the Standby Reserve Check notices issued by the system operator.

Question 12: What is your view of the proposed pre-dispatch and real time indicators for scarcity pricing?

4.5 Final pricing implementation

120. This section discusses the proposed method for modifying final prices when scarcity pricing is invoked. The details of this process are very important because final prices determine the amounts payable by wholesale purchasers, and received by suppliers.

121. It considers the following distinct issues:

(a) the implementation of the scarcity price floor/cap mechanism;

(b) the treatment of nodal and energy/reserve price relativities;

(c) the treatment of part-periods;

(d) the treatment of differences between forecast and actual conditions;

(e) HVDC rentals; and

(f) the stop-loss mechanism.

122. In the cases of (a) and (b), two alternatives are listed (meaning there are four possible combinations in total).

123. The options for the calculation of interim prices in a scarcity pricing situation are set out in a proposed new Schedule 13.3A of the Code in Appendix C of this paper.

4.5.1 Application of scarcity price floor/cap mechanism

124. As discussed in Section 3.2, it is proposed that when scarcity pricing procedures are applied to final prices, a price floor and cap[27] mechanism would be invoked. This mechanism is intended to provide greater revenue certainty for providers of last resort resources, and more assurance for purchasers that spot prices in emergency load shedding will not settle well above the level expected in a workably competitive market.

125. Two sub-options are being considered for the price floor/cap mechanism:

(a) **common values for floor and cap** - in this option, final prices would first be calculated under existing processes[28]. The grid injection prices in the shortage region(s) would then be adjusted up or down to achieve a generation weighted average price (GWAP[29]) in the shortage region of $10,000/MWh (which would place a floor and cap on GWAP at a common value). Adjustments would also be made to grid offtake prices and IR prices in the shortage region(s) to reflect the changes to grid injection prices[30]; or

(b) **different values for floor and cap** - once again, final prices would be calculated under existing processes. In this instance, if the GWAP in the shortage region was lower than $10,000/MWh, an upwards price adjustment would apply along the lines described in (a). Conversely, if the initial GWAP exceeded $20,000/MWh, a downwards adjustment would apply to bring the GWAP to $20,000/MWh. Finally, prices would be set to the GWAP if it was between $10,000/MWh and $20,000/MWh.

126. Under both options the floor/cap mechanism would adjust the ‘market’ price (as measured by GWAP) to the intended level or range. It would not place a strict control on prices at individual nodes (this would be more complex to implement as it would introduce greater risk of revenue insufficiency).

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27 As noted earlier, these terms refer to limitations on the range for an aggregate market price indicator, rather than the price at any individual node.

28 Except that the proposed amendment to pricing in IR shortfalls would apply.

29 For convenience, the examples in this paper use dispatched generation to calculate GWAP. The treatment generation classified as negative demand would need to be considered in the GWAP calculation.

30 The form of these adjustments is discussed in the next section.

127. It is important to note that if a downwards adjustment occurs as a result of applying the scarcity price floor/cap mechanism, it is possible that the final price received by a provider could be below its offer price. It is proposed that no constrained on payments will apply if scarcity pricing is invoked as it would undermine the effectiveness of the floor/capping mechanism.

128. It could be argued that this will weaken incentives to offer resources for dispatch. However, this risk needs to be judged relative to current arrangements, where the effect of any demand curtailment is ignored in final pricing. Under the proposed approach, resource providers would have an assurance that the GWAP will be at least $10,000/MWh[31], and their 'local' price will be reflective of this average.

129. In relative terms, the sub-option with a common floor and cap value is expected to provide more certainty about the level of prices that would prevail during widespread load curtailment as the GWAP would be adjusted to $10,000/MWh. That said, there would still be some variation in prices at individual grid injection and offtake points, with the degree depending on the treatment of nodal price effects (discussed in the next section).

130. Under this sub-option, there would be an appreciable difference between the scarcity price value ($10,000/MWh) and the value of lost load (VOLL) used for regulated transmission investment purposes ($20,000/MWh in December 2004 dollars). However, it is not necessary for these values to coincide. Much residential load has a value far below the average. Emergency load shedding carried out by distributors is expected to be weighted toward load with significantly lower costs of curtailment than the *weighted average cost* for all customers.

131. This divergence of values is evident in Australia where a value of A$47,850/MWh has been applied for transmission planning purposes in Victoria, compared with a scarcity price of A$12,500/MWh in the wholesale market. In this context, the Australian Energy Market Commission stated:

> *"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*

[31] Depending on whether common or different values are adopted for the scarcity price floor and cap mechanism.

weighted average across all sectors], which aligns reasonably close to the MPC [market price cap] of $12 500 that will apply from 1 July 2010"[32]

132. That said, a scarcity price mechanism based on a single value will involve greater approximation than one which uses separate floor and cap values. The latter approach would also have a lower risk of unintended dampening of resource provider incentives. However, this needs to be weighed against the greater uncertainty about price outcomes and the potential for overshooting[33]. The extent of these effects would depend in part on the treatment of nodal price effects and IR price relativities (discussed in the next section).

Question 13: Which approach do you believe will best meet the Authority's statutory objective (and why):

- a common value for the GWAP floor and cap of $10,000/MWh; or

- a GWAP floor of $10,000/MWh and a cap of $20,000/MWh?

4.5.2 Treatment of nodal price effects and IR price relativities

133. Leaving the form of the floor/cap mechanism to one side, if an adjustment to final prices is triggered, a choice arises about the treatment of marginal transmission losses[34] and the relativities between energy and reserve prices.

134. Two sub-options are being considered:

- **Scaled prices**, which would broadly preserve nodal and IR price relativities. Under this sub-option, final prices would be calculated in the normal manner. The first step is to determine the scaling factor to bring the GWAP in the shortage region to the desired level[35]. This scaling factor would then be applied to all energy and reserve prices within the shortage region that were initially calculated in the final pricing solution. This would mean that all price relativities would be preserved, but the overall 'market price' would be scaled up or down; or

- **Flat prices**, which would not preserve the nodal price relativities. Instead, the price at all 'injection nodes' in the shortage region would be set to the desired GWAP level (ie to $10,000/MWh if the floor and cap are set to the same value, otherwise between $10,000/MWh and $20,000/MWh under the alternative). Prices at 'offtake nodes' would be uniform in the shortage

[32] See Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events, *Australian Energy Market Commission*, May 2010

[33] See Appendix B on cost benefit analysis for discussion regarding over-shooting.

[34] Differences due to AC or spring washer constraints would not arise as it is proposed that no scarcity pricing adjustment will be made to final prices if a binding AC transmission constraint in the shortage region is evident in the initial final pricing solution.

[35] As discussed in the previous section, this could be expressed as a value (i.e. $10,000/MWh) or a range (between $10,000/MWh and $20,000/MWh).

region and based on the desired GWAP plus an uplift factor to recover average transmission losses in the shortage region[36]. There is no unambiguous way to determine IR prices in this option. For this reason, it is proposed that IR prices would be set based on the 'most likely expected' condition. This would mean that prices for FIR and SIR would be set to 50% of the price set (e.g. $5,000/MWh) in the shortage region[37].

135. Figure 2 illustrates the application of the two approaches based on a simulated example of forced load shedding being invoked in the North Island[38]. Under existing arrangements, North Island prices would have settled between approximately $4,000/MWh and $6,000/MWh, and South Island prices would be much lower (<$20/MWh).

136. With the scaled price approach, North Island prices would be multiplied by a scaling factor of 2.12 and to settle between approximately $8,500/MWh and $12,800/MWh. South Island prices would be unchanged.

137. With the flat price approach, North Island injection prices would be set to $10,000/MWh and offtake prices would be around 4% higher at $10,390/MWh to reflect average AC losses.

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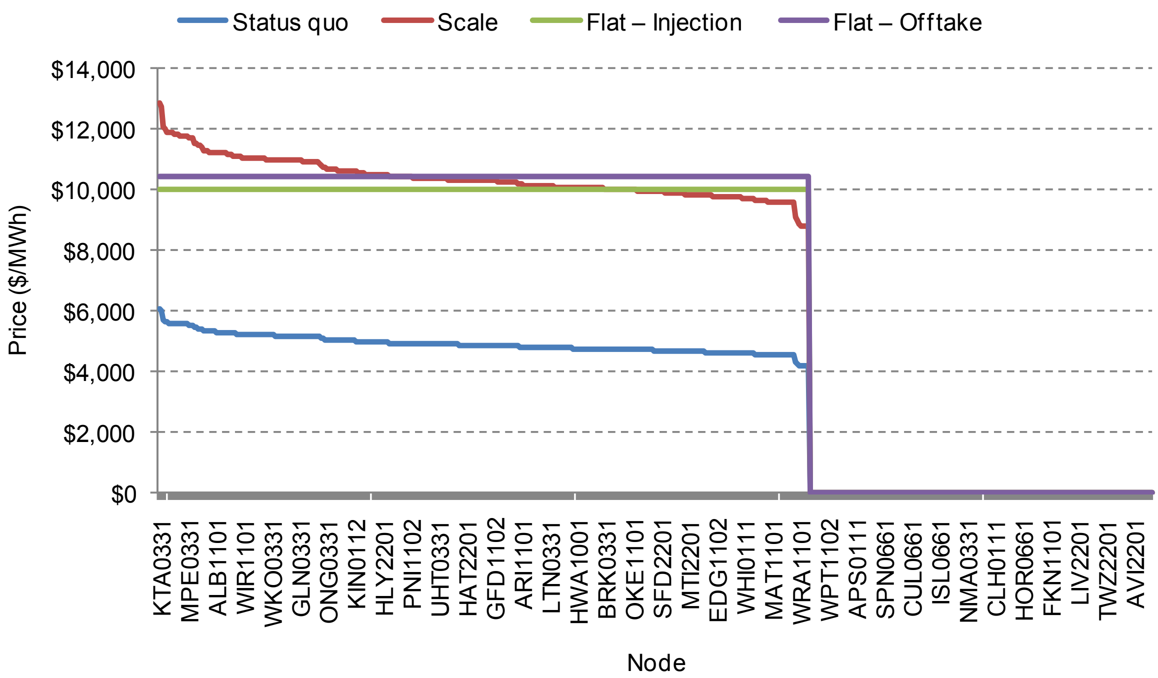
36 The offtake price would apply to any dispatchable demand, in the sense that such providers would avoid the offtake price through their actions.

37 This is based on an expectation that both fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) will both be scarce, and that suppliers can provide both products (and therefore receive GWAP for their combined provision). This is clearly an approximation and will not apply in all circumstances.

38 The example uses data for a trading period where conditions were tight but did not require load shedding. Adjustments have been made to induce the effect of load shedding and subsequent scarcity pricing.

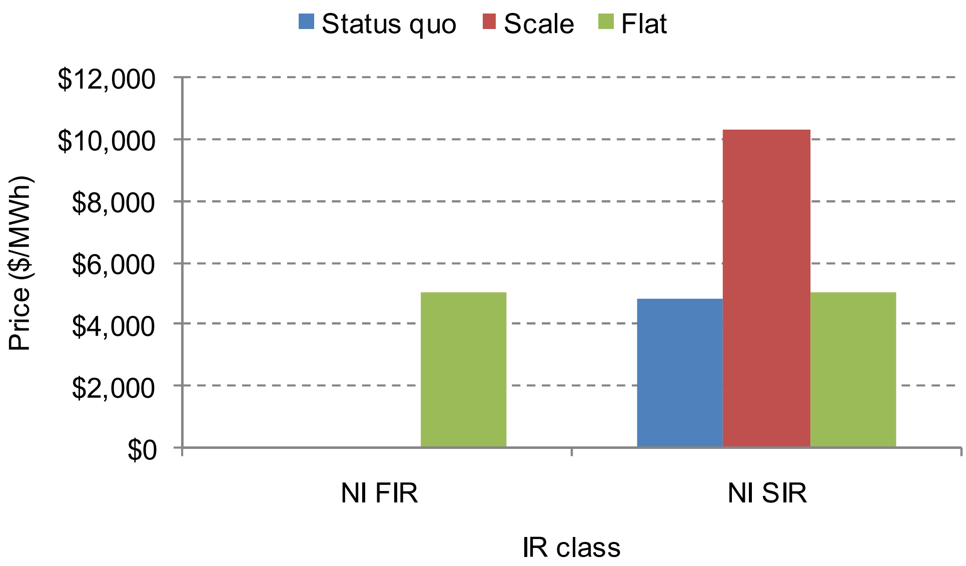
Figure 2: Energy price comparison for 04 July 2010 (17:30) scenario



138. Figure 3 shows the effect of the different approaches on reserve prices. Under existing arrangements, the North Island SIR price would have settled at $5,000/MWh and the FIR price would have been much lower (<$100/MWh) as there was no shortage of this product in the simulated example.

139. With the scaled price approach, FIR prices would have remained relatively low and SIR prices would be multiplied by 2.12 to be approximately $10,100/MWh. With the flat price approach, FIR and SIR prices would have both been set to $5,000/MWh.

Figure 3: NI IR price comparison for 04 July 2010 (17:30) scenario



140. The relative strengths and weaknesses of the approaches have been considered across the following dimensions:

- **degree of certainty** – the flat price option would provide more certainty than the scaled option, since injection prices would be set to a common GWAP if an adjustment is applied, and offtake prices would be the GWAP plus average losses (which are more stable than marginal loss factors for individual nodes);

- **locational signals for demand response and generation** – the scaled approach would provide a signal about where increased generation/reduced load is most valuable in a shortage event. For example, in the simulated case noted above, prices would be $12,824/MWh at Kaitaia and $8,783/MWh at Tuai. Substantial price differences can also arise under normal pricing arrangements if overall spot prices are high. For example, in 6 September 2010 at 17:30 prices at Kaitaia were $6,297/MWh and at Tuai they were $4,735/MWh. From a technical perspective, these differences are appropriate for voluntary load shedding and for locating generating stations, but might not be an appropriate signal during forced load shedding as it implies that curtailment should be concentrated at nodes with the highest incremental losses. This is not the current practice and is unlikely to be acceptable from a societal perspective. These arguments could lend some support to the flat pricing approach;

- **potential effect on locational risk management strategies** – participants face locational price risk in the normal market and seek to manage this risk. Under the flat pricing option, the nature of this risk would change as the system moves between the normal and scarcity conditions. For example, a party with matching generation and load at one location would be perfectly hedged for normal conditions. However, under the flat pricing option, there would be a price difference between the injection and offtake prices to reflect average transmission losses for the whole country or island. This difference would be uniform within the shortage region, even for injections and purchases occurring at the same node. For example, prices at the Wairakei 33kV node in the example would be $10,000/MWh and $10,390/MWh for injection and offtake respectively under the uniform pricing approach, and a single value of $9,584/MWh under the scaled pricing approach. This 'state-change' could mean that risk management strategies for normal and scarcity conditions are not fully aligned. It could also create unintended incentives if any participant is sufficiently large to influence the scarcity pricing triggers;

- **compatibility with locational price risk instruments** – the Authority is proposing to introduce a financial transmission right (FTR) instrument between Otahuhu and Benmore. In the scaled pricing approach, transmission rentals would continue to be generated between Benmore and Otahuhu and would be available to fund the proposed FTR. Thus, the scaled pricing approach should not impact on the effectiveness of the FTR. In the flat pricing option, the rental pool would be reduced to some extent, but so too would be the locational price difference between Benmore and Otahuhu[39]. However, purchasers at Otahuhu in a North Island shortage would still be exposed to the uplift factor to reflect average transmission losses and this would not be hedged by the FTR;
- **consistency between energy and reserve prices** – as noted above, there is no unambiguous way to determine 'consistent' reserve prices under the flat pricing option. This means that anomalies could arise under this option where a reserve price is set to a scarcity level even though there was no shortage of the relevant product (as was the case in the example cited in paragraph 138). Likewise, the adjusted price may be less than the 'true' value for a reserve product in some circumstances[40];
- **incentives to offer resource** – the flat pricing option has a greater likelihood that some resource providers will receive a payment below their offer price. This arises because the 'flattening' process will lower some nodal prices (relative to the scaled approach) given that a common GWAP applies in both cases[41]. Analysis indicates this difference could be around 10% for some nodes based on typical nodal patterns. This means that

[39] In a national event, the difference between the Benmore injection price and Otahuhu offtake price would reflect average national transmission losses. In a North Island event, the difference would reflect average North Island losses.

[40] For example, where only one class of reserve product (FIR or SIR) is scarce, it could be argued that price should be set to GWAP, rather than 50% of GWAP.

[41] Of course, it will increase prices at other nodes. However, that is unlikely to have any bearing on the likelihood of providers receiving a payment below their offer price.

there is a somewhat greater risk of adverse effects on the incentives to provide generation resources or dispatchable demand than for the scaled pricing option;

- **implementation issues** – at present, a single price is established at every grid node for each trading period. The flat price option would introduce the possibility of two prices applying at some nodes – one for generation injection (set at the scarcity value) and the other for purchasers (set at the scarcity value plus a uniform average transmission loss factor). The possibility of two prices at a single node would introduce some additional implementation issues which would need to be taken into account in software changes. There could also be issues for parties with hedge contracts that are referenced against a node where grid injection and offtake occur. At present, a single price will apply for each of those nodes, but two distinct prices could apply during scarcity pricing periods. Parties might wish to make contractual adjustments to reflect this potential;
- **durability** – the scaled price option may enhance durability because there is less discontinuity with status quo arrangements and lower disruption to locational price risk management strategies. However, it rests on an assumption that nodal price differences can be tolerated when scarcity prices are applied. If this was not regarded as sustainable, then the flat pricing option might be regarded as more durable.

141. Ultimately, it is important to recognise that there is no unambiguously 'correct' way to determine prices during load shedding, because the real cost of curtailment will vary by location and over time. There is no methodology available to capture and reflect this information. Nor does overseas practice provide particular guidance in this area because other markets with scarcity pricing differ markedly in their treatment of locational prices. For example, the Australian NEM operates on the basis of zonal (based on each state) rather nodal prices. The Singapore market has a uniform price for load but nodal prices for generation. However, the compact nature of its system means that nodal price differences are relatively small[42].

142. In summary, both pricing options will involve some degree of approximation. The choice involves a trade-off between the desire for certainty (with more inherent approximation) versus a closer representation of individual circumstances (with less certainty).

[42] The electricity market in Texas also uses scarcity pricing and has recently adopted nodal pricing. The scarcity mechanism relies on generators offering at a level to reflect scarcity (but subject to an offer price cap which can be lowered in some circumstances). Under this mechanism, nodal differences to reflect transmission losses and constraints would be expected during scarcity conditions. However, the Texas market also appears to have a relatively extensive financial transmission rights regime. The extent to which this provides a hedge mechanism against locational price differences during 'scarcity' events is not clear from published information.

Question 14: Which approach do you believe will best meet the Authority's statutory objective (and why):

- scaled pricing approach; or
- flat pricing approach?

4.5.3 Application of scarcity price adjustment to trading periods

143. To maintain consistency with other final pricing processes, it is proposed that the final pricing solve would be based on the shortage declaration status in effect at the *start* of a trading period.

144. If the shortage declaration was in force at the start of the period, then the scarcity pricing process for final pricing would apply for the whole of that trading period. For example, if a shortage declaration was made part of the way through trading period 15 and was revoked part of the way through trading period 18, then scarcity price adjustments would apply for trading periods 16-18 inclusive but not for trading periods 15 or 19.

145. This means there could be instances where load shedding is instructed for part of a trading period, but scarcity pricing will apply (or not) for the whole trading period. While this is clearly an approximation, it is consistent with the existing general pricing procedures which are based on conditions at the start of each half hour period. Furthermore, this approach is symmetric in that the 'unders' and 'overs' would be expected to balance over time.

Question 15: What is your view of the proposed approach to applying scarcity pricing across trading periods?

4.5.4 Potential differences between real-time and final pricing conditions

146. Differences will generally arise between real-time conditions (which influence whether a shortage declaration is issued by the system operator) and final pricing conditions. One important difference relates to the curtailed demand itself (which is present in forecast conditions but not in actual conditions). The intention of scarcity pricing is to 'correct' for this particular difference, to ensure that final prices better reflect the expected cost of forced load shedding.

147. Other differences may emerge. In particular, binding transmission constraints may appear in actual conditions that were not present at the time a shortage declaration was made. This may occur as the system is being restored and the area subject to load curtailment retreats from an island shortage to a smaller sub-region.

148. If no specific provision is made to address this issue, it could result in scarcity prices being applied when a shortage only affects part of one island. If the scaled price option is used (see Section 4.5.2), this could lead to large intra-

island price differences, especially as the scarcity price adjustment is linked to the island GWAP[43].

149. To address this issue, it is proposed that the test to detect any binding transmission constraints described in Section 4.2 will be re-run in the final pricing schedule as follows (see proposed clause 13.135A in Appendix C for further detail):

- if a national shortage has been notified at the start of the trading period, a scarcity pricing adjustment would apply for that final pricing schedule provided no binding AC constraint was detected in either island and the HVDC was not subject to a binding constraint. The test would be repeated for each trading period in the final pricing schedule until the national shortage declaration had been revoked (or downgraded to an island shortage declaration);
- If a single island shortage has been notified at the start of the trading period, a scarcity pricing adjustment would apply for that final pricing schedule provided no binding AC constraint was detected in the relevant island and the HVDC was not in operation, or was flowing into the 'shortage' island[44]. The test would be repeated for each trading period in the final pricing schedule until the island shortage declaration had been revoked; and
- If dual island shortage notifications are in force at the start of the trading period, separate scarcity pricing adjustments would apply for each island in the final pricing schedule provided there are no binding AC constraints in either island and the HVDC flow is zero. The test would be repeated for each trading period in the final pricing schedule until the dual island shortage declarations had been revoked or amended.

Question 16: What is your view of the proposed approach to treating differences between forecast and actual conditions?

4.5.5 HVDC rentals

150. Under the scaled and flat pricing options, there is potential for negative transmission rentals to arise on the HVDC link. This risk appears to be relatively remote, but cannot be ruled out entirely. It would arise if:

- load curtailment and scarcity pricing is invoked in one island only;

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43 The large intra-island price differences would not arise with the flat price option. However, it would mean that all nodes in an island are subject to scarcity pricing even though the shortage area is more confined.

44 This is an additional requirement to that used to make a shortage declaration, and is included to reduce the likelihood of negative rentals on the HVDC. This could arise if the HVDC tripped in a trading period, and load shedding was instituted in the island that was previously exporting (e.g. because there was sympathetic tripping of generation plant in that island).

- the application of scarcity pricing *reduces* prices in the shortage island (i.e. the final prices that would otherwise apply are higher than the scarcity pricing cap[45]); and
- prices in the exporting island (not experiencing any shortage) are in the region of the scarcity price cap (allowing for loss adjustments).

151. In these conditions, the scarcity pricing adjustment process would reduce the importing island price to a level that is below the exporting island price, creating negative rentals on the HVDC. The negative HVDC rentals would impact the revenue adequacy of the proposed inter-island financial transmission right (FTR) product, which could compromise the ability to manage this locational price risk.

152. This risk is common to all options that include a scarcity price cap, and it arises in other markets with similar features[46]. If it was judged necessary,, it could be addressed by limiting any downward scaling of final prices to a level where no rental accrues on the HVDC. This means that the GWAP in the shortage region could be above the proposed scarcity price value, but lower than it would otherwise be.

153. However, based on the factors listed in paragraph 150, the risk is expected to be relatively small, and it is therefore proposed that no specific action would be taken to address this issue.

Question 17: What is your view of the proposed approach to HVDC rentals, and what alternative (if any) would you support and why?

4.5.6 Scarcity pricing stop-loss mechanism

154. As noted in Section 3.3, it is proposed that a stop-loss mechanism will be included to limit the application of scarcity prices beyond a pre-defined point[47].

155. If the price floor/cap mechanism is implemented with a common value of $10,000/MWh, it is proposed that the stop-loss mechanism will be expressed in duration terms, and that a 16 hour cut-off would apply for the application of scarcity pricing in any rolling seven day period. This would mean that scarcity pricing could not be applied for more than 32 trading periods in an island during any rolling seven day period. This limit is based on earlier analysis[48]

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[45] That is, the GWAP exceeds $10,000/MWh or $20,000/MWh depending on the sub-option set out in Section 4.5.1.

[46] For example, it arises in the Australian National Electricity Market, and is potentially more acute in that market because the price capping level is much lower at times (~A$300/MWh versus a GWAP of NZ$10,000/MWh).

[47] The mechanism would limit the extent to which scarcity pricing could directly lift prices in any rolling seven day period. However, as discussed in section 3.3, it is not intended that it would limit prices that are high in the absence of scarcity pricing. The issue of generalised price capping mechanisms is a separate issue outside the scope of scarcity pricing.

[48] See www.ea.govt.nz/document/10045/.../our.../spdbtg-meeting-8-july-2010/

which indicates a scarcity price of approximately $10,000/MWh should be revenue adequate for a last resort provider, if a cumulative limit over seven days was set at around $1,000/MWh in weekly average price terms.

156. If the scarcity price/floor cap mechanism is implemented with separate values, it is proposed that the stop-loss limit will be based on the cumulative GWAP for the previous 336 trading periods (i.e. one week) in the relevant island. If the cumulative figure is $168,000 (i.e. an average of $1,000/MWh for a week) or more, then scarcity pricing adjustments would not be applied to final prices in the current period in that island.

157. The cumulative price test would be calculated from interim final prices[49]. These should provide a workable basis for applying the stop-loss test, because interim prices for the previous week should generally be available when calculating interim final prices for the current period.

158. The options for the stop-loss mechanism are set out in clause 13.135C of the proposed Code amendments in Appendix C.

Question 18: What is your view of the proposed approach to implementing a scarcity pricing stop-loss mechanism?

4.6 Shortfall in instantaneous reserves

159. As noted in Section 3.6, a modification to final pricing will be included to reduce the potential for spot prices to settle at levels that are many multiples of the highest energy or IR offer following an IR shortfall which triggers an infeasible solution in final pricing.

160. The modification is based closely on that proposed in the previous consultation paper, where a 'virtual' IR provider would be added to the final pricing solution. However, the original modification has been simplified in light of submissions and further analysis.

161. Previously, it was proposed that the virtual IR provider would be offered at the greater of the highest dispatched IR or energy offer, or a scarcity value from a pre-defined IR shortage function. It is now proposed that a virtual provider of fast instantaneous reserve and sustained instantaneous reserve will be added to the final pricing solution, with the offer price set at the highest energy offer or reserve offer scheduled during the relevant trading period.

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[49] The alternative would be to use published final prices. However, these may not be available for a considerable time (perhaps weeks) after real time in some circumstances.

162. It is proposed that a new clause will be added to the Code to provide for the pricing manager to recalculate and publish interim prices if an infeasibility situation that has been resolved was caused by a shortage of IR (see clause 13.166A in Appendix C).

Question 19: What is your view of the proposed modification to final pricing when an IR shortfall occurs and an infeasible solution arises in final pricing?

5 Stress-testing regime

Section summary

- The proposed regime would require wholesale market participants to apply a set of standard stress tests to their electricity market positions and report the results on a confidential basis to the Authority. For each test, participants would be required to disclose the resulting change in net cash flow from operating activities (NCFO), relative to a defined base case scenario.
- To minimise administration costs, the stress tests would be framed in general terms, and participants would use their own systems for estimating the resulting financial impacts. Disclosures would be required for the coming quarter on a rolling quarterly basis. The Authority would also have the ability to request an update if required.
- The disclosure requirement would cover generators, retailers, any person who consumes electricity that is conveyed to the person directly from the national grid, and any other person who buys electricity from the clearing manager.
- The proposed regime would not directly cover other parties (e.g. medium sized businesses) exposed to spot prices through their electricity supply contract. Instead, it is proposed that disclosing participants would be required to certify that they have provided such customers with information to enable each customer to assess the risk associated with the contract and consider the outcomes of applying the stress test or stress tests to the customer.
- To ensure that participants apply due care in preparing disclosure statements, there would be a requirement for the statements to be signed by two directors, and a provision for independent audit.
- Beyond the reporting requirements, the regime would not impose any mandatory obligations on participants. It would not constrain participant choices in the electricity or hedge markets, and participants would retain full responsibility for managing their risk exposures.

5.1 Basic design

163. The proposed regime would require participants to apply a set of standard stress tests to their electricity market positions. The results of applying these tests would be reported to the Authority on a confidential basis. Stress-testing regimes of this general type have applied for a number of years in the financial sector[50], including New Zealand's banking sector[51].

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[50] The application of stress-testing in the financial sector in Australasia is discussed in a recent paper from the Australian Prudential Regulation Authority, see www.apra.gov.au/Insight/upload/Insight_Issue_2_2010_article_r.pdf

164. Participants would retain full responsibility for managing their risk exposures. However, the fact that they must report the impact of the standard stress tests on their electricity market position is expected to alter their behaviour and place the Authority in a more informed position to deflect opportunistic lobbying and, just as importantly, identify legitimate concerns with market performance.

165. In particular, the stress testing regime would reduce the scope for wholesale participants to credibly claim that they were unaware of the risks associated with their chosen level of spot market exposure, as everyone (including the media) would know the party was required to undertake the stress tests and has had the opportunity to arrange hedge cover.

166. Furthermore, in conjunction with initiatives it is undertaking in the hedge market, the proposed stress testing regime would place the Authority in a better position to assess the strength of claims about market effectiveness. For example, in past periods of high prices, claims have arisen that suitable risk management products were not available to mitigate spot price risk.

167. The Authority is working closely with ASX Limited and the five largest generators to establish more robust and credible forward price curves for the electricity futures and options market. Transparent and competitive pricing of dry year hedge cover will be substantially enhanced by the provision of market making on option contracts extending out for two to three years. This initiative, which should be in place by mid 2012, will reinforce the effectiveness of the stress testing regime proposed in this paper.

168. The proposed stress testing regime would also provide information that assists the Authority to fulfil its broader market monitoring functions under section 16 of the Electricity Industry Act, and to identify priorities for future Code development.

169. It is proposed that the stress testing regime will form a new subpart 5A of Part 13 of the Code. The proposed subpart 5A is set out in Appendix C.

5.2 Information to be disclosed

170. The aim of disclosure is to measure the degree of financial stress caused by a high spot price event. For this reason, it is proposed that the disclosure be based on reporting the change in net cashflow from operating activities (NCFO) from applying each stress test, relative to a defined base case.

171. Focusing on the change in NCFO has a number of advantages:

- NCFO is a measure that is widely used and understood in the business sector. This should make it easier to compile for disclosing parties;

[51] For example, see http://www.rbnz.govt.nz/research/bulletin/2007_2011/2011jun74_2hargreaveswilliamson.pdf

- NCFO is difficult to manipulate because it is not affected by non-cash items (such as valuation changes);
- by focussing on the change in NCFO, parties are not required to reveal a forecast of their expected earnings under normal conditions (which could be a concern for some parties, especially those listed on a stock exchange).

172. While the change in NCFO will provide a robust measure of the impact of the stress test event, some comparator information is required to assess the significance for the party concerned. For example, a deterioration of $1 million in NCFO will be more serious for a smaller participant than a larger party.

173. For this reason it is also proposed that parties would be required to disclose:

- NCFO from the most recent set of audited annual accounts; and
- the level of Shareholders' Equity from the most recent set of audited accounts.

174. These two measures respectively provide an indication of the party's ability to absorb a 'hit' to their:

- cash earnings; and/or
- capital reserves.

175. Because the comparator data is historic, it should not raise concerns about disclosing forward looking financial information (which as noted above can be a potential issue for some parties).

176. Lastly, it would be useful for the Authority to obtain information on the forecast volume of load associated with each disclosing party (i.e. the total volume of spot purchases). This information should be relatively easy for parties to collate, and would significantly assist the Authority in interpreting the results of stress tests. Furthermore, the Authority could compare the aggregate volume with total demand to identify any gaps in the coverage of the stress testing regime.

177. In summary, it is proposed that parties would be required to disclose to the Authority:

- the change in NCFO, for each stress test;
- NCFO from the most recent set of audited annual accounts; and
- the level of Shareholders' Equity from the most recent set of audited annual accounts; and
- the forecast volume of load to be purchased from the spot market for each disclosing party.

Question 20: What is your view of the proposed information to be disclosed?

5.3 Nature of stress tests to be applied

178. Given the desire to maintain simplicity and transparency, it is proposed that the stress tests be framed in terms of two key variables:

- spot prices in the event; and
- duration of the event.

179. This means that participants would simply be asked to report the change in NCFO if spot prices averaged $x/MWh rather than $y/MWh (the base case level) for a defined duration of z weeks.

180. In setting the values of x, y and z, it is very important to consider the underlying purpose of the tests, which is to reduce the scope for participants to credibly claim they are unaware of spot market risks, and to assess the resilience of the system (including the risk of contagion) to possible shocks.

181. Participants would retain *full* responsibility for making choices about their own risk positions. Accordingly, the tests would not be a substitute for tailored risk analysis that each wholesale party should carry out, reflecting its unique generation, load, hedge position, access to capital and assessment of market risks.

182. Nor are the tests intended to represent ‘worst case’ scenarios for the system or any particular participant. There will always be scenarios that are more demanding (e.g. lower hydro inflows or thermal fuel availability, increased plant outages etc). Each participant would need to make it own judgement about the risks that it faces, and conduct its own analysis to assess those risks. The stress testing regime would not remove these responsibilities from participants.

5.4 Examples of possible stress tests

183. The tests would be specified by the Authority from time to time, and be publicised for use by relevant parties. It is proposed that separate tests would be applied to assess resilience in an energy context and in a capacity context. The energy tests are expected to vary somewhat across the year to reflect the seasonal variation in hydrology and demand (and hence risk). The capacity tests are expected to be uniform across the year.

184. An indication of the possible tests is set out below. These will be further refined if the stress testing regime is adopted.

5.4.1 Stress test 1 – Possible dry year events

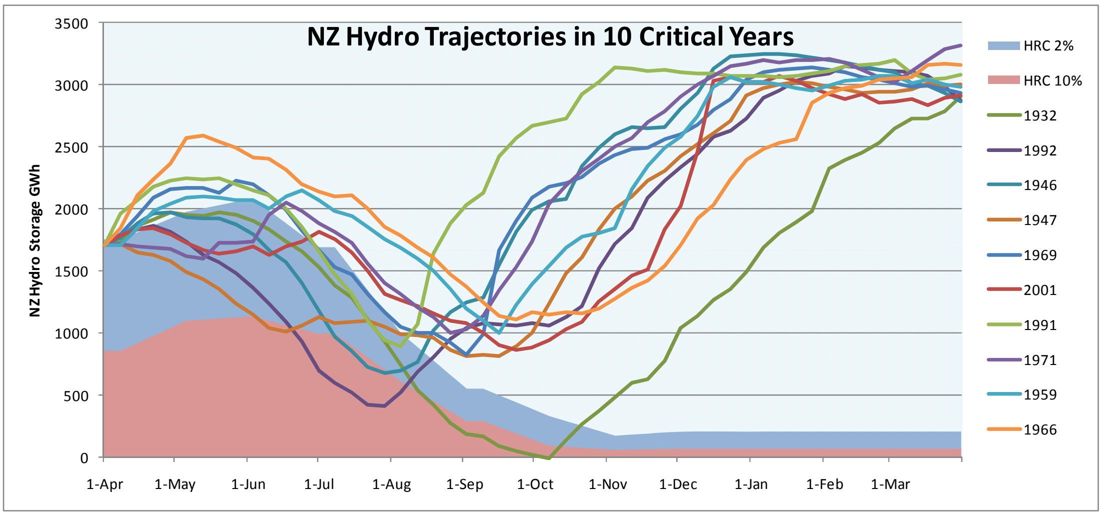
185. Two tests with differing severities are proposed, with the key difference being that the less severe test would not involve a public conservation campaign.

5.4.1.1 **Stress test 1A – Dry year event (no public conservation campaign)**

186. A possible test for a winter disclosure[52] is that spot prices over 13 weeks are at a daily average level of $500/MWh.

187. The proposed duration is based on an examination of historic hydro inflow sequences over winter periods. Figure 4 shows the expected affect if national hydro storage on 1 April is at the 2% hydro risk curve, and any of the 10 most critical sequences were to be repeated[53]. There is considerable variability in the sequences, but on average storage remains below the 2% hydro risk curve for 13 weeks.

Figure 4: Hydro trajectories



188. Another point of comparison is the most recent significant drought event of 2008. Table 3 shows the length of time that hydro storage was below the so-called minzone which roughly corresponds to the 2% hydro risk curve. For New Zealand as a whole, storage was below the minzone for 13 weeks, and for the South Island the duration was even longer (though it was close to the minzone from late July).

Table 3: Duration that hydro storage was below minzone in winter of 2008

2008 data	Entered minzone	Exited minzone	Weeks
National storage	10-Apr	12-Jul	13
South Island storage	20-Apr	2-Sep	19

189. The expected level of spot prices during an extended drought would depend on the specific circumstances at the time (e.g. inflow and storage levels, demand trends, plant availability etc). As points of comparison, the proposed $500/MWh daily average is close to the short run marginal cost of a diesel

52 This is the test that would be applied in late March for the coming winter.

53 In each case it is assumed that thermal production is maximised subject to transmission constraints and plant capacity. Note that these sequences reflect the expected position once Pole 3 of the HVDC is commissioned.

fired plant (currently estimated to be around $475/MWh) and similar to the Energyhedge contract price (around $450/MWh) in winter of 2008[54].

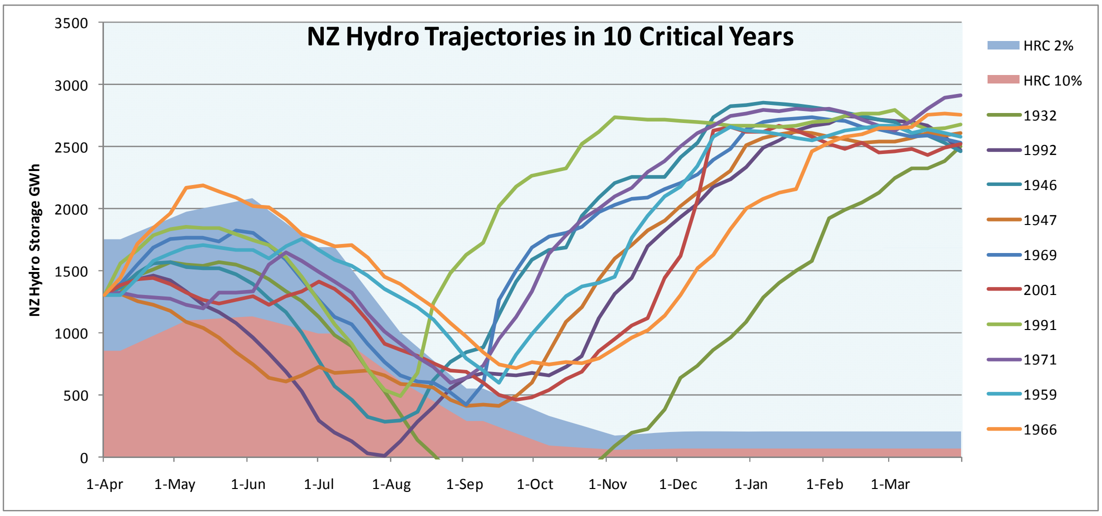
190. It is proposed that the winter test would be applied in late March for the coming quarter with the 13 week stress test price applied for the whole quarter. The 13 week test would also be applied for the coming six months (i.e. April-September). In this case, the stress test period would apply for the six weeks to 30 June and the seven weeks from 1 July (i.e. it would straddle the mid-winter period).

191. Separate energy tests would be developed for application in June, September and December.

5.4.1.2 Stress test 1B – Dry year event (including public conservation campaign)

192. It is also proposed that a more severe test would also be applied in which conditions could trigger a public conservation campaign. Such a scenario could occur for a variety of reasons, such as a lower level of starting storage (illustrated in Figure 5 with all other factors unchanged) and/or thermal plant constraints.

Figure 5: Hydro trajectories – more severe event



193. To make it straightforward to apply, it is proposed that this stress test would have the same general features as the previous scenario, except that the 13 week event would be broken into two phases:

- Phase 1 – a seven week period that mirrors the conditions of stress test 1A; and

54 Energyhedge prices later fell when the Whirinaki offer price was held at $289/MWh rather than moving with increasing diesel costs.

- Phase 2 – a six week period where average spot prices are $750/MWh and mass-market demand is reduced by 8%.

194. Like the previous test, this stress test would be applied in late March for the coming quarter, and for the coming six months.

5.4.1.3 Other possible parameters

195. There is also the issue of whether the pricing scenarios should consider the stresses of prices being sustained for extended periods at relatively low levels, such as $25/MWh for example. There may also be value in stress testing with average prices of $150/MWh or $250/MWh for a quarter, as a point of comparison with the $500/MWh prices proposed in stress test 1A. This would reveal whether aggregate spot market exposure varies significantly across these price points, due to the availability of standby generation and financial option contracts.

5.4.2 Stress test 2 – Possible short-term capacity shortages

196. The previous tests are designed to assess resilience during extended periods when energy supply is tight.

197. Two different stress tests are proposed to assess resilience to shorter capacity-related shocks. The two proposed scenarios differ in severity, with the more severe event triggering the application of a stop-loss mechanism (assuming one is implemented). It is proposed that these tests would be applied for a nationwide capacity shortage, but there may also be value in considering an event which is confined to the North Island (at least until Pole 3 of the HVDC is commissioned).

5.4.2.1 Stress test 2A – Capacity event (no stop-loss triggered)

198. The proposed test is that spot prices are $10,000/MWh for 6 hours, followed by 6 hours at $5,000/MWh.

199. The test would reflect a scenario where a sudden asset failure occurs during a peak demand period. Prices rise without warning to $10,000/MWh for 6 hours. The situation is partially stabilised, but there is insufficient capacity to provide normal reserve cover. Under this scenario, the time weighted average price for the affected week would be around $620/MWh[55].

5.4.2.2 Stress test 2B – Capacity event (stop-loss triggered)

200. It is proposed that a more severe test would also be applied which reflected the parameters of any stop-loss mechanism that is implemented.

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[55] Assuming prices are $100/MWh at off peak times.

201. For example, if the stop-loss mechanism suspended the application of scarcity pricing after 16 hours, the weekly average spot price would be around \$1,000/MWh.

202. In this case, the test would be applied over two successive days where spot prices are \$10,000/MWh for 8 hours in the peak demand periods.

Question 21: What is your view of the indicative stress test parameters?

5.5 Extent of guidance/prescription

203. Participants would use their own tools to undertake analysis for the stress testing regime. To promote consistency, some general guidance would be provided to participants on the application of the stress tests. An indication of the proposed form of the guidance is set out in Table 4.

Table 4: Indicative guidance for stress tests (winter period disclosure)

	Dry year events		Capacity shortages	
Period covered	Coming quarter, and coming six months	Coming quarter, and coming six months	Coming quarter	Coming quarter
Load	Expected normal load less any contracted or firm demand response capability	Same as 1A but allow 8% reduction in mass market demand for 6 weeks	Load in highest hours of system demand. Allowance for demand response included to extent it is reliable.	Same as 2A
Hydro generation	Opening storage + inflows based on expected contribution in worst 5% dry year at *national* level for relevant period (~1 in 20 standard)		Capacity de-rated to allow for average expected flows at time of year, any commitment issues and shorter term energy constraints	
Wind generation	Average contribution for time of year for relevant period		De-rated to reflect average capacity expected for time of year	
Thermal/geothermal generation	Expected capability accounting for fuel constraints and outages (planned and forced)		Capacity de-rated to allow for any commitment issues, outages, and fuel constraints	
Nodal price effects	Estimated by participant based on loss factors and daily price shapes expected in a dry year when there are North to South transfers		Estimated by participant based on loss factors and daily price shapes expected in a short term capacity event affecting both islands	
Energy hedges	Include all existing contracts at date of disclosure. Future contracts are excluded unless they can be exercised unilaterally in relevant timeframe (e.g. a firm option to extend an existing contract).		Include all existing contracts at date of disclosure. Future contracts are excluded unless they can be exercised unilaterally in relevant timeframe (e.g. a firm option to extend an existing contract).	
Locational hedges	Net revenue from loss and constraint rentals or expected net revenue from contracted FTRs (where applicable)		Net revenue from loss and constraint rentals or expected net revenue from contracted FTRs (where applicable)	
Customer compensation costs	Include costs in accordance with any contractual obligations	Same as 1A plus costs of Code scheme	Include costs in accordance with any contractual obligations	

204. Again, it is important to note that this guidance has been framed with the intention of assessing potential system stress events, rather than worst case scenarios or events that could impact on specific participants. The parties themselves should consider other scenarios for their own internal purposes.

Question 22: What is your view of the proposed level of guidance to be provided to participants?

5.6 Frequency and timing of disclosures

205. Net exposure of parties can change relatively rapidly, especially as they buy or sell hedge contracts. For this reason, it could be argued that relatively frequent disclosure would be desirable. On the other hand, the compliance costs of the regime will increase with the frequency of disclosure.

206. In light of these factors, it is proposed that disclosure statements would be required on a quarterly basis, and would be required to be submitted no later than five business days before the beginning of a quarter. It is proposed that the energy stress tests would cover the next three and six month periods, and the capacity-stress tests would cover the coming three month period.

207. There would also be provision for the Authority to require parties to update their disclosures on specific request.

Question 23: What is your view of the proposed frequency of reporting?

5.7 Scope of parties covered

208. The disclosure requirement should cover the parties with potential material exposure to spot prices (and therefore a potential incentive to call for conservation campaigns). It should therefore include generators, retailers, any person who consumes electricity that is conveyed to the person directly from the national grid, and any other person who buys electricity from the clearing manager.

209. While this would cover most large parties directly exposed to spot prices, it would not capture smaller parties that take on spot price risk through their electricity supply contracts. It would be important to consider these types of exposures because past experience suggests that significant economic costs can arise in this area (e.g. commercial users that purchase spot electricity via an agent).

210. For this reason, it is proposed that disclosing participants would be required to certify that they have provided their customers (who are exposed to spot market risk) with information about the stress tests and recommended they undertake the test to assess the risks associated with the supply contract. There would be no requirement, however, for disclosing participants to check that their customers have undertaken the test or to collect stress test results from their customers.

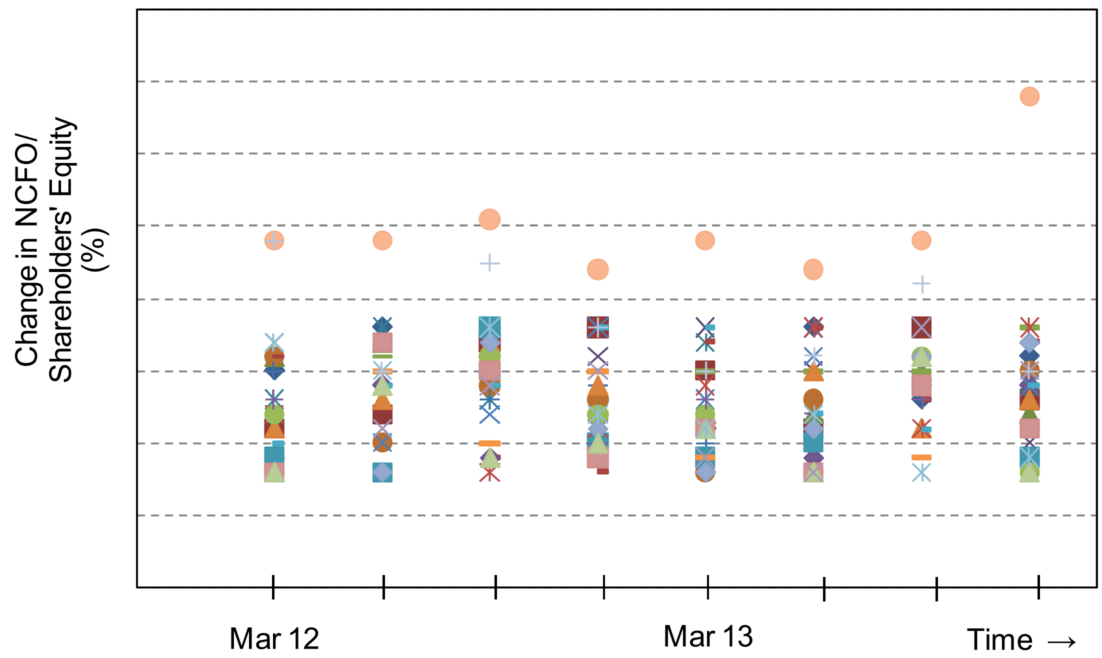
Question 24: What is your view of the proposed coverage of a disclosure obligation?

5.8 Use of information

211. As noted earlier, the stress test information provided to the Authority would be confidential. While individual disclosures would not be released, the Authority would publish disclosure information in a summarised form that does not associate specific information with any disclosing participant.

212. For example, it might publish the risk exposures expressed in ratio terms. Publishing the distribution could be particularly useful as it would allow participants to see if they are outliers in terms of the stress test results, and to track the overall results through time. A mock-up of a possible chart for inclusion in a summary report is shown in Figure 6.

Figure 6: Example of possible summary for a stress test



213. The summary report could also be useful during a supply event if lobbying occurs for earlier use of public conservation campaigns and/or other market changes. The Authority could use the information to help assess whether lobbying reflects a systemic issue, or is driven by a more narrow interest.

Question 25: What is your view of how information disclosed could be used?

5.9 Compliance and auditing

214. It is important that the decision-makers in control of the disclosing party are aware of the material being disclosed, and stand by the accuracy of the information.

215. For this reason, it is proposed that disclosure statements would require the same level of sign-off as company annual reports and financial statements. These require the signature of two directors, or the sole director if the company has only one director.

Furthermore, the directors that sign the statement would be required to confirm that the stress test disclosure statement has been considered by the board.

216. It is also proposed that the Authority would have the right to request an independent audit of a disclosure statement.

217. A failure to make proper disclosure would constitute a breach of the Electricity Industry Participation Code and allow for application of the sanctions provided in the Code. If an alleged breach is upheld by the Rulings Panel, it can make compliance or compensation orders, or impose pecuniary penalties of up to $200k per breach. If the participant does not comply with an order from the Rulings Panel, the Panel can make a suspension or termination order against that participant in certain circumstances.

Question 26: What is your view of the proposed compliance and auditing arrangements?

6 Regulatory Statement

Section summary

- There is significant risk that the efficient level of reliability will not be realised under current arrangements. The proposed Code amendments are intended to address this by improving price formation during widespread emergency load shedding. The proposed stress testing regime would strengthen incentives to prudently manage risks, and reduce the ability of parties to credibly lobby for early use of emergency measures or ad hoc policy changes during periods of system stress to lower prices. The proposed Code amendments are therefore expected to contribute to meeting the reliability limb of the Authority's statutory objective.
- In relation to the competition limb of the Authority's statutory objective, the proposed Code amendments are expected to be positive in overall terms as they will enhance competition for the provision of last resort generation and demand response resources.
- In relation to the efficient operation limb of the Authority's statutory objective, the proposed changes are expected to be positive in overall terms. This is because the changes should provide greater assurance that the efficient level of security and reliability will be provided by the electricity system.
- The scarcity pricing proposal is estimated to have potential economic benefits of approximately $40 million to $138 million in net present value terms. Sensitivity testing indicates that net benefits are expected even under a range of potential downside scenarios.
- The primary benefit of the stress testing regime is expected to be stronger economic growth due to greater confidence in security of supply, and correcting the perception that New Zealand is unduly vulnerable to supply crises. If this was the only benefit, even an extremely small increase in gross domestic product 1/2000th to 1/5000th of one percent per year would be sufficient for the regime to yield net benefits. Alternatively, if the regime had no impact on business confidence but only increased the expected return period for public conservation campaigns, even an incremental improvement of 6-12 months would be sufficient for the stress testing regime to yield net benefits.
- In light of these factors, the Authority is proposing Code amendments to introduce scarcity pricing and the stress testing regime.

6.1 Objective of proposal

218. 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.

6.2 Assessment against the Authority's statutory objective

219. Section 32(1) of the Act requires that any amendments to the Code are consistent with the Authority's statutory objective, which is promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers[56].

220. The Authority considers that the proposed scarcity pricing and stress-testing regime is consistent with the Authority's statutory objective. In assessing the proposal against the Authority's statutory objective, it is useful to break-down the 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.

6.2.1 Limb 1: Competition in the electricity industry

221. 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*"[57]

222. In terms of incentives for participants to enter and exit the market, scarcity pricing and the stress testing regime are expected to enhance competition for provision of last resort generation and demand response resources, as potential providers would have more surety about the rewards from entering that market. Moreover, both scarcity pricing and the stress testing regime should increase incentives for consumers and net retailers to hedge with providers of last resort plant. This in turn would increase the surety of returns to providing last resort plant, which should increase competition for the provision of those resources.

223. The stress testing regime should also give providers of last resort resources (both supply and demand side) more confidence that ad hoc price suppressing initiatives will not be adopted in a future emergency, further encouraging entry into that market.

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[56] Section 15 of Electricity Industry Act 2010

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

224. As noted in the previous consultation paper[58], the introduction of scarcity pricing is not expected to alter the time weighted *average* wholesale price over the longer term[59]. 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. In this respect, the indicative 1 June 2013 start date should provide sufficient lead time.

225. Scarcity pricing could change the *volatility* of spot prices. In this context, the proposed Code changes could be expected to narrow the range of possible price outcomes during IR shortfalls (the most frequent type of emergency) by removing the possibility that prices settle at many multiples of the highest energy or IR offer. In respect of emergency load shedding, the proposed Code changes are also expected to provide more certainty about price outcomes – relative to the status quo where prices could be below the level necessary to provide adequate incentive for provision of last resort resources or well above the level expected in a workably competitive market.

226. 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[60] 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.

227. In relation to the proposed stress testing regime, this is expected to encourage greater hedging activity, which could increase competitive pressure in the spot market and subsequently in the hedge market. It does not appear likely that the regime will give rise to adverse competition outcomes as it does not constrain participant choice or behaviour in the electricity or hedge markets.

228. 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 scope for any unintended adverse competition effects to arise from the introduction of scarcity pricing or the stress testing regime.

229. In conclusion, based on present information, it is expected that the proposed changes would contribute to meeting the competition limb of the Authority's statutory objective.

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58 See Section 6.5 of 'Scarcity Pricing – Proposed Design', *Electricity Authority,* March 2011.

59 Nor is the stress testing regime expected to alter the time weighted average price over the longer term.

60 By reducing offered quantities and/or increasing the offer prices for existing quantities.

6.2.2 Limb 2: Reliable supply by the electricity industry

230. 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.*"[61]

231. Under current arrangements, there is significant risk that the efficient level of reliability will not be realised. Instead, it is more likely that the system will tend to provide a lower level of reliability over time. This can manifest itself through unduly tight supply margins (under-investment), sub-optimal unit commitment and fuel management decisions (having sufficient plant, but not utilising it efficiently), or foreclosure of voluntary demand-side response options because spot prices are suppressed during supply emergencies. None of these outcomes is in the long term interest of consumers, as they will experience more near misses or forced load shedding than is desirable.

232. As set out in Section 2 of this paper, 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 forced load shedding, 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.

233. In addition, parties can have an incentive to over rely on emergency measures (such as public conservation campaigns) as a form of risk mitigation. This in turn can create an incentive to talk up supply risks with the objective of accelerating the use of emergency measures[62]. These factors combine to undermine the incentives on parties to prudently manage risks, and achieve the efficient level of reliability.

234. The changes being proposed are intended to directly address these issues. The price formation process during emergency load shedding would be changed so that a price floor and cap is applied. In respect of instantaneous reserve shortfalls, price formation

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

[62] The Authority has recently determined that the trigger point for starting a public conservation campaign will be hydro storage falling below the 10% 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 trigger points. Furthermore, the calculation of the trigger conditions is subject to a number of areas of judgement by the system operator. For these reasons, the incentive on some participants to talk up the level of supply risk has not been entirely eliminated.

would remain largely unchanged, except there would be reduced potential for extreme prices to emerge when the market clearing engine is near the limit of feasibility. In all cases, price outcomes are, on average, expected to better reflect the costs associated with IR shortfalls or emergency load shedding.

235. The stress testing regime is designed to strengthen the incentives on participants to prudently manage risks. In particular, it would reduce the ability of participants to credibly claim that they are unaware of spot market risks. The regime will also provide valuable information to the Authority for its market monitoring and Code development functions.

236. The Authority has 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*." [63]

237. The Authority's proposals are expected 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 generation) 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. Second, the proposed changes should reduce the potential for spot price suppression or significant 'overshooting' during forced load shedding, because of the use of the price floor/cap mechanism, and stop-loss arrangement, which will limit the application of scarcity pricing.

238. The stress testing regime is expected to strengthen the incentive for participants to prudently manage their positions. This in turn should also reduce the risk of an ad hoc intervention.

239. The Authority has considered whether the proposed arrangements could have the unintended consequence of making reliability worse. This 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

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

internally consistent framework. They also appear reasonable in relation to other comparator data – for example the prices at which participants are prepared to offer demand-response on a voluntary basis. This issue is also explicitly considered as a sensitivity case in the cost benefit analysis;

- 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, even if values are set too low relative to the economic ideal, it is likely that outcomes will be an improvement relative to the status quo (where spot prices are likely to be suppressed to levels below the proposed scarcity value); 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 be less efficient, relative to the counter-factual.

240. In light of these factors, the Authority expects that the proposed scarcity pricing arrangements and stress testing regime would contribute to meeting the reliability limb of its statutory objective.

6.2.3 Limb 3: Efficient operation of the electricity industry

241. 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*[64]".

242. 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.

243. 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 239, it believes that the proposed changes are likely to be beneficial, relative

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

to the counter-factual. It also notes that the stress testing regime has been designed to use participants' existing risk measurement tools as far as possible, and avoid undue transactions costs.

244. Finally, the Authority has considered the extent to which the efficiency gains from the proposed changes will be shared with consumers. The Authority notes that consumers ultimately bear the costs of adverse outcomes under current arrangements, in the form of increased risk of load shedding and reduced opportunity for voluntary demand-response. The proposed changes are designed to address these issues.

245. In conclusion, the Authority expects that the proposed changes would contribute to meeting the efficient operation limb of its statutory objective.

Question 27: What is your view of the proposals when assessed against the Authority's statutory objective?

6.3 Alternative means of achieving the objective

246. The previous section concluded that the proposed changes would be consistent with the Authority's statutory objective. This section considers whether there are alternative means of achieving the objectives of the proposed changes.

6.3.1 Capacity mechanism

247. A capacity mechanism was identified as a feasible alternative to scarcity pricing and was discussed in the previous consultation paper[65]. In summary, the Authority considered that a capacity mechanism could offer similar reliability benefits to scarcity pricing, but may be better at lowering the risk of ad hoc intervention during or after a supply emergency.

248. However, a capacity mechanism would be expected to require more prescription than scarcity pricing. This may impede the process of adopting innovations, and may over time reduce the efficiency of operation of a capacity mechanism relative to the alternatives. For this reason, the Authority considered scarcity pricing to be preferable to introducing a capacity mechanism at this time.

249. The Authority retains this view, and considers that it would be preferable to adopt the proposed scarcity pricing and stress testing regime. If these do not achieve the desired outcomes, the Authority would re-consider whether the introduction of a capacity mechanism will have net benefits.

6.3.2 Single buyer option

250. The option of moving to a centralised single buyer model was raised in submissions on the previous consultation paper.

65 See section 6.3 of 'Scarcity Pricing – Proposed Design', *Electricity Authority,* March 2011

251. This option has been considered in the past by a number of bodies. It would entail a fundamental change to existing market-based dispatch, as all wholesale energy would be purchased and sold by a single entity. That party would also control all unit commitment, dispatch, fuel management, and plant maintenance decisions.

252. This would create significant transition costs and risks. Nor is it clear that centralised decision-making would necessarily yield economic benefits in terms of security (recalling that some supply shortages occurred under the central decision making approach that applied prior to 1996). Furthermore, it is not clear whether the Authority has sufficient powers under the Electricity Industry Act 2010 to implement such an option.

253. In light of these factors, this option is not considered to be a superior alternative to the proposed stress testing regime and scarcity pricing.

6.3.3 Short-term forward commitment market

254. The option of introducing a short term forward market (STFM) for the day or week ahead was raised in submissions as a better alternative to scarcity pricing. The stated benefit was that it would allow both demand and supply side participants to be directly involved in determining prices during supply emergencies (and other times). This was seen as preferable to determining prices using current arrangements (based on a generator offer and metered demand) or scarcity pricing (an administered floor/cap determined by the Authority).

255. Direct participation in price formation by demand and supply side participants is highly desirable. A STFM could be a useful advance toward this objective. However, a day-ahead commitment market was implemented in 1996 as part of New Zealand's original wholesale market design. Participation was voluntary and there was little uptake by either supply or demand side parties, leading to its abandonment. For a forward commitment market to be effective, it might be necessary to make participation compulsory. While it is relatively straightforward to compel parties to submit forward bids and offers, it is more difficult to ensure that these reflect 'genuine' forecasts of future intent (bearing in mind that any significant divergence could introduce a bias to the forward price).

256. Another key issue is addressing the needs of participants with unpredictable forward requirements (e.g. purchasers with significant demand variability, wind generators and run-of-river hydro plants). In essence, a balance would need to be struck between the reducing the flexibility (and efficiencies) of some participants (e.g. run of river hydro, variable demand sources) in order to gain forward commitment (and efficiencies) valued by other participants (e.g. slower start thermal plant, industrial load).

257. A STFM may also need to be integrated in some way with existing voluntary hedge markets to reduce the scope for parties to be exposed to new risks. For example, it may be desirable to settle voluntary hedge contracts against the forward commitment price rather than the spot price, as the former would apply to most traded volume, and the latter would only apply to residual imbalances between parties' planned and actual volumes. This may raise some transition issues for parties with longer term contracts.

258. Lastly, while it is possible that a STFM might improve price formation in extended supply emergencies (e.g. droughts), it is unlikely to have any material effect during short term capacity emergencies because the demand bids and supply offers in the STFM (and hence the forward price) will reflect conditions before the emergency arose.

259. In summary, a STFM:

- may offer price formation benefits during extended shortage situations, but it would not alter price suppression during short term supply emergencies;
- may facilitate greater demand side participation, which has wider benefits; and
- would be a significant change and raise important issues for generators with uncertain production patterns and/or consumers with uncertain load schedules.

260. For these reasons, the Authority does not regard a STFM as a viable alternative to the proposed stress testing regime and scarcity pricing. However, the Authority will consider the merits of an STFM as a possible subsequent measure to the current proposals to facilitate greater demand-side participation in the wholesale market (ie the Demand Side Bidding and Forecasting and Dispatchable Demand projects).

Question 28: What is your view of the alternative means of achieving the objectives of the proposed scarcity pricing and stress-testing regime?

6.4 Benefits and costs of proposed changes

6.4.1 Framework

261. A cost benefit analysis of the proposed changes has been undertaken[66] which separately evaluates the proposed scarcity pricing changes and the stress testing regime.

262. The analysis is undertaken from an economy-wide perspective, weighing expected costs and benefits to New Zealand over a 30 year period.

6.4.2 Cost benefit analysis of scarcity pricing

263. Scarcity pricing is expected to provide greater certainty about spot price outcomes in situations when emergency measures are invoked. This is expected to improve investment and operational incentives for both demand-side and supply-side parties as set out in Table 5.

[66] The analysis is set out in Appendix B and further quantitative information (including spreadsheets) is available on the Authority website.

Table 5: Scarcity pricing benefit categories

	Demand-side	**Supply-side**
Investment decisions	Stronger incentive to invest in demand-side capability (either pre-emptive or real time) where this is more economic than the cost of forced load-shedding (as signalled in scarcity price)	Stronger incentive to invest in last resort plant where this is more economic than cost of forced load shedding (as signalled in scarcity price)
Operational decisions	Greater scope for voluntary price-based demand response where this is more economic than cost of forced load shedding (as signalled in scarcity price)	Stronger incentive to commit slow start generation units where net expected cost of commitment is lower than cost of forced load shedding (as signalled in scarcity price)
Other	Greater assurance that spot prices will not settle significantly above the cost of curtailment in an IR shortage or forced load shedding event	Lower likelihood of an ad hoc policy intervention during or after a load shedding event, which in turn should enhance longer term investment confidence

264. The main expected cost associated with scarcity pricing is the software changes required to the market clearing engine. The analysis includes a one-off cost of $2.5 million plus $100k per annum for software maintenance from year two. An allowance of $500k per review has been made for costs associated with three yearly reviews of scarcity pricing parameters.

265. Scarcity pricing is expected to alter electricity spot prices during shortage events. This could give rise to wealth transfers among different parties. While such transfers could affect the distribution of costs and benefits, they are expected to offset each other in the aggregation of total effects for New Zealand[67].

266. Table 6 summarises the estimated benefits and costs of the proposed scarcity pricing changes.

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[67] This assumption was adopted in the previous consultation paper and was queried by some submitters. The Authority has given this issue further consideration, and for the reasons set out in Appendix B believes that it is an appropriate approach in the current context.

Table 6: Scarcity pricing estimated costs and benefits

$m NPV	**Lower**	**Higher**
Costs		
Implementation costs	(5)	(5)
3 yearly reviews	(2)	(2)
Total	(7)	(7)
Benefits		
Investment signalling	27	92
Unit commitment	14	30
Additional demand response	6	24
	47	145
Net benefits	40	138
Ratio of benefits : costs	6.7	20.8

267. In summary, scarcity pricing is expected to yield net benefits of around $40-138 million in present value terms.

268. The key driver for this range is the degree to which spot prices are suppressed during shortages in the absence of scarcity pricing. If spot prices settle at the highest generator offers observed until 2010 (i.e. around $3,500/MWh), the expected net benefit would be toward the upper end of the range. On the other hand, if spot prices settle at around $5,000/MWh in shortages[68], then expected net benefits would be toward to the lower end of the range. However, in either case, a strong benefit/cost ratio is evident.

269. For completeness, it is important to acknowledge the possibility that no spot price suppression will occur in the absence of scarcity pricing. In that case, no direct benefit would accrue from scarcity pricing. However, even if this were the case, adopting scarcity pricing could be preferable to the status quo. The reason for this view is that scarcity pricing has a relatively modest cost (around $7 million NPV), but provides insurance against outcomes which could be much more costly (i.e. $47 – 146 million in NPV terms) if price suppression does occur. Furthermore, the likelihood of these costly outcomes will only be known in hindsight. Accordingly, scarcity pricing could be seen as a useful insurance against undesirable outcomes.

6.4.3 Cost benefit analysis of stress testing regime

270. The expected benefits of the stress testing regime include:

[68] Bearing in mind that the reserve energy scheme and administered capacity offer price for Whirinaki will cease upon sale of that plant.

- reducing the damage to broader economic confidence and growth that arises from parties ‘talking up’ the level of security risk and lack of competition when the system is tight;

- reducing the expected frequency of public conservation campaigns, by making it harder for parties to lobby for early use of campaigns without revealing their financial motivation;

- strengthening incentives for parties to prudently manage their exposures to spot price risk, with flow-on benefits in terms of more procurement of voluntary demand-side response, improved fuel management, investment/retention of energy reserve capability etc;

- providing information to the Authority on the extent of systemic exposure to spot price risk in the wholesale market (which can inform decisions around matters such as the transitional stop-loss mechanism); and

- providing information to assist the Authority in fulfilling its broader market monitoring functions under section 16 of the Electricity Industry Act.

271. These benefits overlap in some areas and it is difficult to quantify them based on a ‘bottom-up’ approach. Instead, this analysis proceeds by asking ‘what degree of improvement’ would be required to breakeven in overall economic terms, based on plausible cost estimates.

272. The primary benefit of the stress testing regime is expected to be stronger economic growth due to greater confidence in security of supply and greater confidence that electricity prices reflect competitive levels during supply shortages. If this was the sole benefit, gross domestic product (GDP) would need to be higher by 1/2000th to 1/5000th of one percent per year for the regime to yield net benefits. This is an extremely small improvement, and given the important role that electricity plays in almost every sector of the economy, this change would appear to be well within the plausible range.

273. The likelihood of net benefits has also been assessed assuming that there is no improvement in wider economic growth. Instead, it identifies the change in public conservation campaign frequency that would be required to obtain net benefits. The analysis is based on the following assumptions:

- society incurs a cost of $93 million if a public conservation campaign occurs. The $93 million estimate is based on the assumptions adopted for the Customer Compensation Scheme cost benefit analysis undertaken in 2010[69]; and

- the expected return period for public conservation campaigns is 10 years *in the absence of a stress testing regime*. This estimate is based on the assumed return period if a Customer Compensation Scheme is in operation.

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[69] See pp.67-86 of ‘Customer Compensation Schemes’, Consultation Paper, Electricity Commission, October 2010.

274. This analysis indicates that if the expected return period for public conservation campaigns was increased from 10 years to 10.4 – 11 years, this would be sufficient to offset the estimated costs of the stress testing regime[70]. This is an extremely small change in return period and appears to be well within the plausible range of outcomes that might be expected.

275. In conclusion, based on the assumptions and analysis set out in Appendix B, it is considered highly likely that the proposed stress testing regime would have positive net benefits from an economic perspective.

Question 29: What is your view of the costs and benefits of the proposed scarcity pricing changes?

Question 30: What is your view of the costs and benefits of the proposed stress testing regime?

[70] Depending on the cost of the regime and number of parties that are covered.

7 Authority's preferred option and proposal

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

- are consistent with the Authority's statutory objective;
- are preferred over the alternative means of achieving the objectives of the proposals described in section 6.3; and
- will yield substantial long-term positive net benefits for electricity consumers.

7.1 Attachments

277. 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 sets out information on the cost benefit analysis for scarcity pricing; and

(c) Appendix C which sets out the proposed changes to the Electricity Participation Code.

Question 31: Do you propose any changes to the proposed Code amendments set out in Appendix C?

Appendix A Specific matters

The Authority seeks feedback on the issues and proposals discussed in this Consultation Paper, and the draft proposed Code amendments set out in Appendix C.

Parties are also invited to provide their views on the following specific questions:

Question 1:	Do you agree with the problem definition?
Question 2:	Do you agree that the proposed narrowing of scarcity pricing (to be applied for short-term emergencies and not for extended shortages) would be more consistent with the Authority's statutory objective?
Question 3:	Do you agree that scarcity pricing should be applied as a price floor and cap, rather than simply a price floor during emergency load shedding?
Question 4:	Do you agree that scarcity pricing should include a stop-loss mechanism, at least on a transitional basis?
Question 5:	Do you agree that scarcity pricing should not apply for AUFLS per se?
Question 6:	Do you agree with the proposed geographic threshold for initial application of scarcity pricing, and if not why?
Question 7:	Do you agree that an amendment should be made to final pricing processes when an infeasible solution arises following an IR shortfall?
Question 8:	Do you agree with the proposed implementation timetable?
Question 9:	What is your view of the proposed review provisions for key scarcity pricing parameters?
Question 10:	What is your view of the trigger mechanism for declaring a national or island shortage?
Question 11:	What is your view of the trigger mechanism for revoking shortage declarations?
Question 12:	What is your view of the proposed pre-dispatch and real time indicators for scarcity pricing?
Question 13:	Which approach do you believe will best meet the Authority's statutory objective (and why): - a common value for the GWAP floor and cap of $10,000/MWh; or - a GWAP floor of $10,000/MWh and a cap of $20,000/MWh?
Question 14:	Which approach do you believe will best meet the Authority's statutory objective (and why): - scaled pricing approach; or

	- flat pricing approach?
Question 15:	What is your view of the proposed approach to applying scarcity pricing across trading periods?
Question 16:	What is your view of the proposed approach to treating differences between forecast and actual conditions?
Question 17:	What is your view of the proposed approach to HVDC rentals, and what alternative (if any) would you support and why?
Question 18:	What is your view of the proposed approach to implementing a scarcity pricing stop-loss mechanism?
Question 19:	What is your view of the proposed modification to final pricing when an IR shortfall occurs and an infeasible solution arises in final pricing?
Question 20:	What is your view of the proposed information to be disclosed?
Question 21:	What is your view of the indicative stress test parameters?
Question 22:	What is your view of the proposed level of guidance to be provided to participants?
Question 23:	What is your view of the proposed frequency of reporting?
Question 24:	What is your view of the proposed coverage of a disclosure obligation?
Question 25:	What is your view of how information disclosed could be used?
Question 26:	What is your view of the proposed compliance and auditing arrangements?
Question 27:	What is your view of the proposals when assessed against the Authority's statutory objective?
Question 28:	What is your view of the alternative means of achieving the objectives of the proposed scarcity pricing and stress-testing regime?
Question 29:	What is your view of the costs and benefits of the proposed scarcity pricing changes?
Question 30:	What is your view of the costs and benefits of the proposed stress testing regime?
Question 31:	Do you propose any changes to the proposed Code amendments set out in Appendix C?

Appendix B Cost Benefit Analysis

Introduction

B.1 This appendix analyses the costs and benefits of the proposed scarcity pricing changes and the stress testing regime. Although the proposals are related, they are separable and have been treated as distinct items for the purposes of cost benefit analysis.

B.2 A common framework has been applied across both proposals. In particular:

- the analysis is undertaken from an economy-wide perspective based on incremental costs and benefits;
- the timeframe for assessment is 30 years;
- values are estimated in 2012 dollars and an 8% real discount rate has been applied; and
- the counterfactual assumes that existing arrangements will apply, except where changes have been announced as firm decisions (for example, the abolition of the Reserve Energy Scheme and sale by the Crown of the Whirinaki plant).

Proposed scarcity pricing changes

B.3 This section examines the expected costs and benefits of the proposed set of scarcity pricing changes, which are:

- a price floor/cap mechanism to be applied during widespread load shedding;
- changes which fine-tune the final pricing processes for IR shortages; and
- a stop-loss mechanism to curtail the application of scarcity pricing once a pre-defined limit is reached.

B.4 It is not practical to estimate the specific effect of each individual change and they have therefore been evaluated as a package. It is assumed that they take effect from 2013.

B.5 A number of submitters on the previous consultation paper commented that they found the cost benefit analysis difficult to follow, and that it was a ‘black-box’. To address these issues, this cost benefit analysis describes the estimation process in more detail. Copies of the underlying spreadsheets have been published on the Authority website for parties that wish to examine the quantitative analysis in greater depth.

B.6 Some submitters on the previous consultation paper also noted differences in some assumptions between the cost benefit analysis and an earlier paper prepared for the Scarcity Pricing Technical Group. A reconciliation of these differences is included later in this Appendix.

Cost benefit analysis of scarcity pricing

B.7 Scarcity pricing is expected to provide greater certainty about spot price outcomes in situations where emergency measures are invoked. In particular, the proposal would provide more assurance that spot prices will not be suppressed below the GWAP 'floor' in forced load shedding. Similarly, the 'cap' aspect of the scarcity price mechanism, the adoption of the IR pricing change, and the stop-loss mechanism are expected to provide more assurance that spot prices will not settle at levels that are significantly above the expected cost of curtailment during an IR shortfall or load shedding event.

B.8 These changes are expected to improve investment and operational incentives for both demand-side and supply-side parties as set out in Table 7.

Table 7: Scarcity pricing benefit categories

	Demand-side	**Supply-side**
Investment decisions	Stronger incentive to invest in demand-side capability (either pre-emptive or real time) where this is more economic than the cost of forced load-shedding (as signalled in scarcity price)	Stronger incentive to invest in last resort plant where this is more economic than cost of forced load shedding (as signalled in scarcity price)
Operational decisions	Greater scope for voluntary price-based demand response where this is more economic than cost of forced load shedding (as signalled in scarcity price)	Stronger incentive to commit slow start generation units where net expected cost of commitment is lower than cost of forced load shedding (as signalled in scarcity price)
Other	Greater assurance that spot prices will not settle significantly above the cost of curtailment in an IR shortage or forced load shedding event	Lower likelihood of an ad hoc policy intervention during or after a load shedding event, which in turn should enhance longer term investment confidence

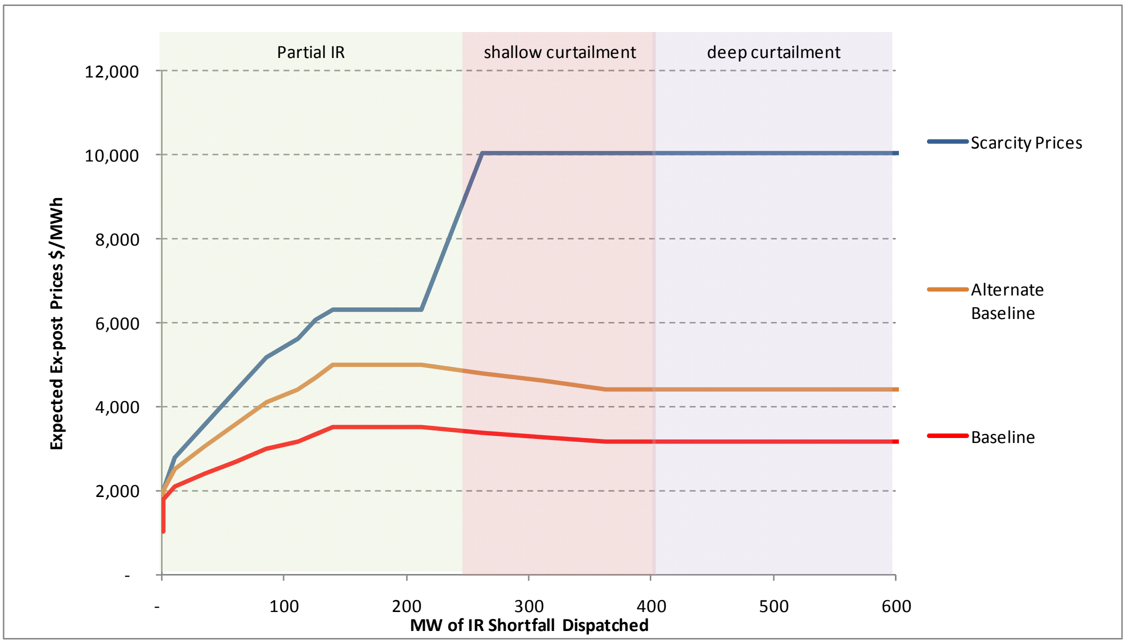
B.9 The following sections discuss these benefit categories where they can be reasonably quantified.

Scarcity pricing – investment signalling benefit

B.10 To estimate the investment signalling benefits, it is necessary to make assumptions about the expected level of spot prices with and without scarcity pricing. This data can be combined with information on the frequencies of different market states (i.e. IR shortfall, forced load shedding) to derive the expected revenue for a last resort plant (i.e. a plant that will earn most of its revenue in these states).

B.11 The pricing assumptions that have been adopted for this analysis are shown in Figure 7. They are unchanged from those adopted in the previous consultation paper[71].

Figure 7: Spot prices during supply emergencies



B.12 In summary, the pricing cases are:

- Baseline – spot prices average around $3,500/MWh during larger IR shortfalls and demand curtailment events (this is based on the highest supply offers typically observed prior to the change to the Whirinaki capacity offer in 2010); and

- Alternative baseline – where spot prices average around $5,000/MWh during larger IR shortfalls and demand curtailment events (this assumes that supply offers increase from those historically observed, and 'mirror' the current Whirinaki capacity offer). This case appears feasible, but investors may be reluctant to 'rely' upon a $5,000/MWh offer as being sustainable once the Reserve Energy scheme is fully phased out; and

- Scarcity pricing - spot prices are assumed to average $10,000/MWh when load shedding is invoked[72]. Spot prices in IR shortfalls are assumed to be higher than under the baseline case, but lower than the scarcity price value itself. This

[71] See Appendix E of 'Scarcity Pricing Design', Consultation Paper, March 2011.

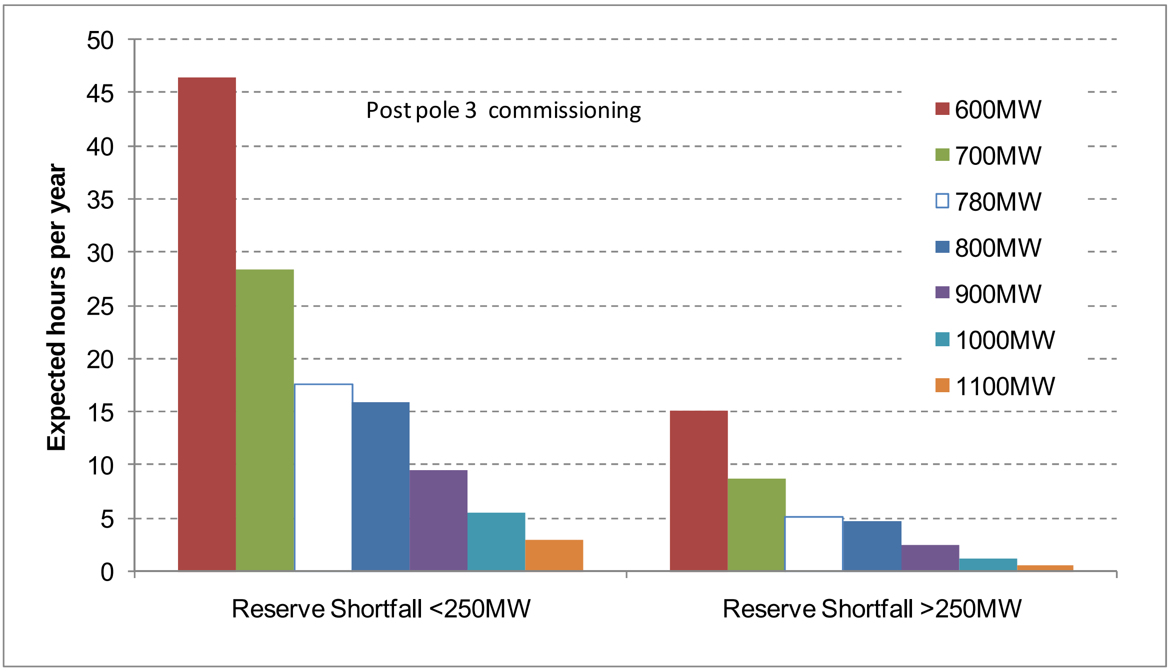
[72] Noting that this is likely to be invoked before IR cover is reduced to zero.

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

B.13 This information is combined with data on the expected frequency of the different market 'states'[73] to estimate the revenue that a last resort plant would be expected to earn under the baseline and scarcity pricing cases.

B.14 The expected frequency of different market states depends on the capacity margin for the system. The frequency assumptions adopted for this analysis are shown in Figure 8 and reflect the expected position once Pole 3 of the HVDC is commissioned in late 2012. The current winter capacity margin standard is 780MW, and represents the expected 'optimal' capacity[74]. At that system margin, IR shortfalls up to 250MW would be expected for approximately 18 hours/year on average and instructed demand curtailment (when IR shortfalls exceed 250MW) for approximately 5 hours/year on average[75].

Figure 8: Expected frequency of shortfalls



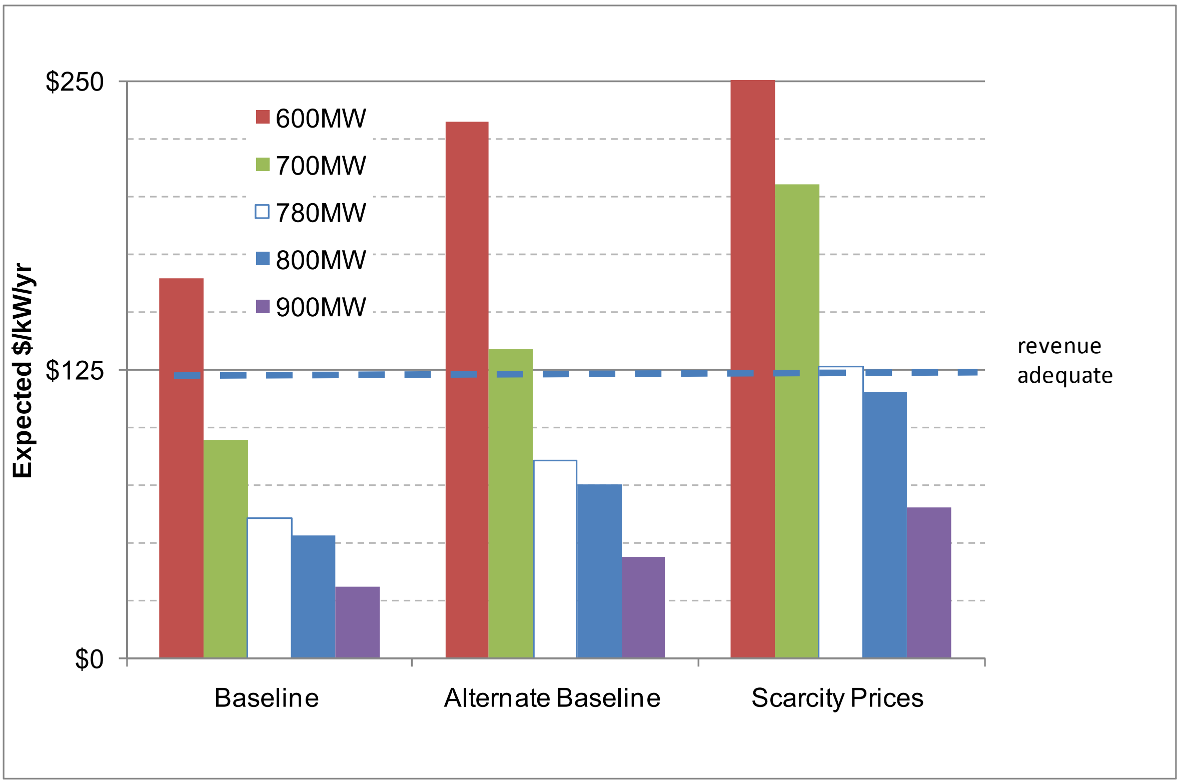
73 More specifically, the relative frequency of no shortages, IR shortfalls (without load shedding) and load shedding events.

74 For more detail, see http://www.ea.govt.nz/document/2230/download/industry/ec-archive/security-of-supply/security-of-supply-policies-archive/.

75 Note that the previous consultation paper reported 16.3 hours up to a 200MW IR shortfall and 6.8 hours beyond 200MW at the 780MW capacity margin. This chart shows an expected 5 hours beyond 250MW IR shortfall and 18hrs below 250MW. The difference simply relates to the slight reclassification of reserve shortfall events. The reclassification reflects the likelihood that the system operator may call for pre-emption load reductions at around this level of IR shortfall to avoid the risk of system collapse.

B.15 These assumptions about price outcomes and frequency of shortfalls have been used to estimate the revenue for a last resort plant under different capacity margins. The results are shown in Figure 9.

Figure 9: Expected revenue for last resort oil-fired plant



B.16 The chart also shows the required revenue for a last resort provider of capacity to break even[76]. Under the baseline and alternate baseline cases, the last resort provider would have insufficient revenue to break-even at the optimal capacity standard (780MW). Instead, the capacity margin would be expected to fall below that standard over time[77].

B.17 This implies that in the absence of scarcity pricing, the system would have a lower capacity margin and higher level of forced demand shedding than would be optimal from society's perspective. The economic cost of this divergence can be estimated

[76] This assumes the plant has a capital cost of $145/kW/year and an operating cost $350/MWh. This operating cost differs from the *current* Whirinaki short run marginal offer price of $472/MWh. However, the former figure represents a longer term expected average, whereas the latter reflects current conditions. It also assumes that the last resort capacity provider can earn $20/kW/year on average during 'dry' periods where prices will be high but there is no IR shortfall or load shedding. In reality, some peaking capacity may be able to earn additional revenue in other non-scarcity periods. However, by definition not all of the peaking capacity would be scheduled for dispatch and earn revenue. By definition, the last resort provider will be reliant on prices in shortage periods for much of its revenue. For further information see Appendix E of 'Scarcity Pricing Design', Consultation Paper, March 2011.

[77] With scarcity pricing, a last resort provider of capacity would just break-even under the assumptions set out above. Of course, this is expected as the scarcity price value is derived to ensure revenue adequacy for a last resort provider when the system operates at a 780MW margin.

by considering the additional social cost of curtailments, less the saving in capacity investment, relative to the position at the optimal capacity margin.

B.18 This has been undertaken using the non-supply costs adopted for the North Island capacity standard developed in 2008, but updated for inflation. The non-supply costs are summarised in Table 8.

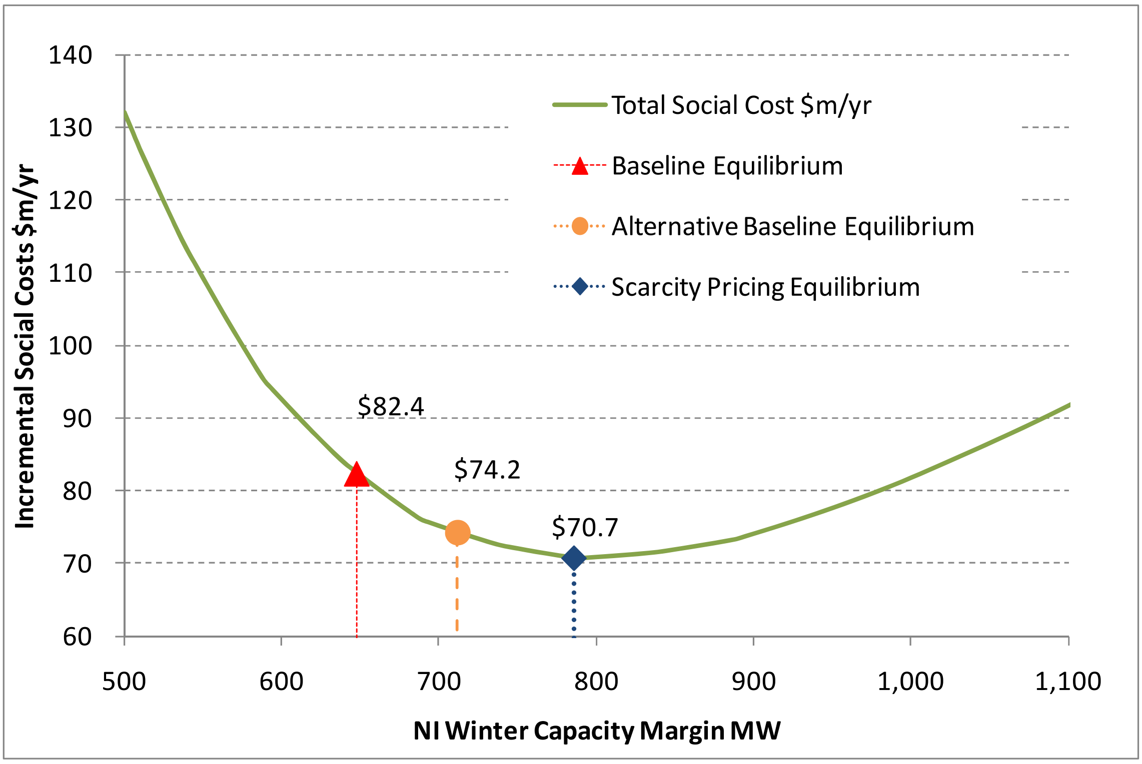
Table 8: Average Social Costs of capacity shortfall[78]

Tranche	Depth of Capacity Shortfall	Avg Social Cost k$/MWh
1	Risk of AUFLS with up to 100 MW IR shortfall	$2.0
2	Risk of AUFLS with 100-200 MW IR shortfall	$4.0
3	Risk of AUFLS with 200-250 MW IR shortfall	$8.8
4	250-400 MW IR shortfall - 3% shallow pre-emptive load shedding	$10.5
5	Beyond 400 MW IR shortfall - deeper pre-emptive load shedding	$24.9

B.19 This information is combined with the estimated costs for a last resort provider to plot the total system costs (supply cost plus expected cost of curtailment) for differing capacity margins as shown in Figure 10.

[78] Note that the tranches in this table have been modified from that provided in supplementary information for the previous consultation paper to better reflect the fact that the system operator may initiate pre-emptive demand shedding for IR shortfalls greater than 250MW. This does not represent in a change in the underlying cost curve it simply reports average costs over different bands.

Figure 10: Combined cost of non-supply and supply for different capacity margins



The marked points show the expected equilibrium capacity margin and associated system cost with scarcity pricing, and under the two baseline cases. The expected total annual system cost with scarcity pricing is lower than either of the baseline cases, as summarised in Table 9.

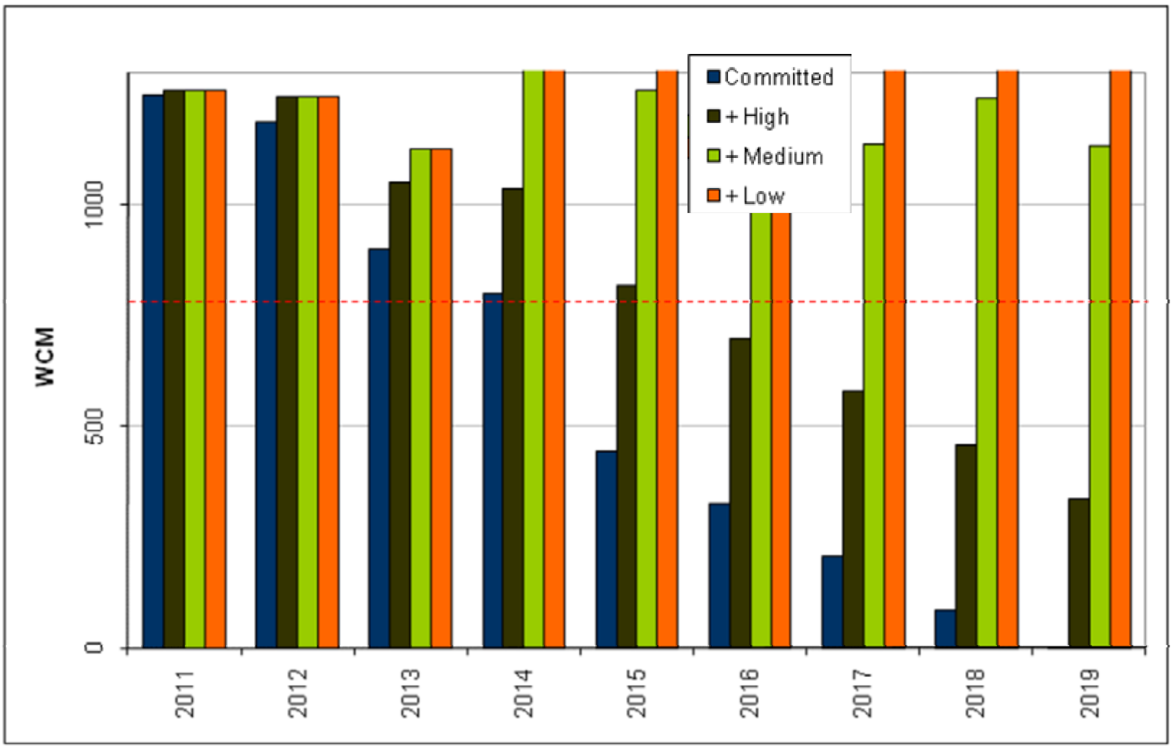
Table 9: Annual economic costs real $m per year

	Proposal	Baseline	Alternative Baseline
Equilibrium Capacity Margin	786	648	712
Shortfalls GWh/yr	3.9	8.8	6.1
Social Cost of Shortfalls $m	$21.0	$49.9	$33.7
Extra Peaker Fixed Cost $m/yr	$49.7	$32.5	$40.5
Total Cost $m/yr	$70.7	$82.4	$74.2
Implied Benefit from Scarcity Pricing $m/yr	$0.0	$11.7	$3.5

B.20 It is important to note that the estimates in Table 9 represent averages that would be expected over time under the relevant pricing assumptions. The most recent

Annual Security Assessment published by the system operator[79] projected a near term capacity margin that is higher than these levels. For 2013 (the first year when scarcity pricing would apply), the system operator projected the capacity margin to be 900 MW based on "committed" projects, and declining to around 800 MW the following year. The Annual Security Assessment also included other projections based on uncommitted but possible projects, as shown in Figure 11[80].

Figure 11: Projected Winter Capacity Margin (Annual Security Assessment 2011)



B.21 In light of these projections, this analysis does not include any investment benefits during the next five years. Nonetheless, benefits are expected to accrue from later years. The key reason for this view is that under the pricing assumptions in the baseline cases, it would not be rational for participants to invest in, or retain, plant to maintain a capacity margin of 780 MW (or more), as last resort plant could not expect to recover its costs under those conditions.

B.22 The question may be posed as to why sub-optimal capacity margins have not been observed to date. In this context, it is important to note that New Zealand has historically experienced periodic energy constraints, but has had relatively abundant capacity resources due to the characteristics of its hydro generation base. In effect, energy constraints were the key driver for investment and capacity has little distinct value in its own right. It is widely recognised that the nature of the system is

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79 'Annual Security Assessment 2011', system operator, January 2011

80 Since the Assessment was published, some new projects have been committed for development.

changing and that capacity adequacy will be a more challenging issue going forward.

B.23 Furthermore, it is important to note that the existing Reserve Energy Scheme based on the Whirinaki plant has effects that are in some respects analogous to a scarcity pricing scheme for capacity, in that a $5,000/MWh 'scarcity price' applies if the plant is scheduled and dispatched to provide short term capacity support[81]. The reserve energy scheme will end once the plant is sold by the Crown (expected before 2013), removing the 'quasi-scarcity pricing' mechanism provided by the Whirinaki capacity offer price.

B.24 For the purposes of the cost benefit analysis, the assumption has been made that no scarcity pricing benefit will accrue in the investment context before 2017[82]. This year has been chosen because the capacity margin projected by the system operator based on committed projects is more than 500MW below the optimal level in that year. Furthermore, even with an additional 400MW of 'highly likely' projects included, the projected margin for that year was well below 780MW[83].

B.25 It is also important to note that the system operator's projections are significantly influenced by assumptions regarding the available capacity of the Huntly station. The projected margins assume that beyond 2015 two units are maintained for service, and that they are committed early enough to ensure reliable supply. Scarcity pricing would be expected to strengthen the incentive for Huntly units to be maintained and committed, provided the cost of doing so is lower than the cost of alternatives.

B.26 In summary, an investment signalling benefit of $11.7 million per year has been estimated for scarcity pricing relative to the baseline, and $3.5 million per year relative to the alternative baseline. In both cases, the analysis assumes that the benefits only start to accrue from 2017. In present value terms, this equates to $27 million - $92 million.

Scarcity pricing – unit commitment benefit

B.27 Greater certainty about pricing in load shedding events, and the flow-on impact to pricing in IR shortfalls, should result in more efficient unit commitment decisions. In particular, it should reduce the risk of forced load shedding being required because slow start units were not committed for operation ahead of time, and were therefore

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81 Unlike scarcity pricing per se, this scheme operates prior to actual curtailment events and has undesirable distorting effects on operating and investment incentives in the 'normal' market.

82 As noted earlier, *existing* investment decisions may be based in part on an expectation that some form of scarcity pricing will apply. To the extent this is correct (and there is some anecdotal evidence in support of this view), the assumption of zero benefit until 2017 could be regarded as conservative.

83 Some additional projects have been committed since the Annual Security Assessment was issued in January 2011. It is likely that these were classified by the system operator as "High" likelihood in the 2011 Assessment. Even with these additional projects, the capacity margin is well below 780 MW in 2017.

not available to address an unexpected demand increase, fall in intermittent generation levels and/or plant failure.

B.28 Past experience indicates that unit commitment can be a significant issue, even during periods where the overall winter capacity margin is adequate (e.g. during 2009 there were a number of ‘near miss’ events despite the ‘nameplate’ margin being above 780MW). Furthermore, the risk is heightened during periods when the system capacity margin is above the long run equilibrium level.

B.29 This is an important issue in the current context because the analysis set out above regarding investment signalling effectively treats unit commitment decisions as being close to ideal, irrespective of the system capacity margin. In fact, for the next few years (when the capacity margin is expected to be above the longer term equilibrium), there is a heightened risk of poor unit commitment outcomes.

B.30 The change in forced load shedding probability due to unit commitment issues has been estimated using an analytical framework presented to the Scarcity Pricing and Default Buyback Technical Group[84] in October 2010. For given information about unit start-up and running costs etc, it examined the likelihood of a ‘mean’ shortage pricing event (SPE[85]) occurring under different assumptions about price outcomes during load shedding.

B.31 This analysis has been updated to reflect the latest scarcity pricing and baseline pricing assumptions. It indicates that the risks of unit commitment issues are greatest when forecast day-ahead spot prices are relatively low (e.g. in shoulder periods when there is high forecast wind generation or hydro inflows). In these situations, the level of SPE risk is likely to be approximately 1-2% per day higher in the alternative and baseline scenarios, than under the scarcity pricing proposal. This is a result of price suppression in baseline scenarios which undermines the incentive on parties to commit units (and therefore lower the risk of load shedding). This information is shown in Figure 12[86].

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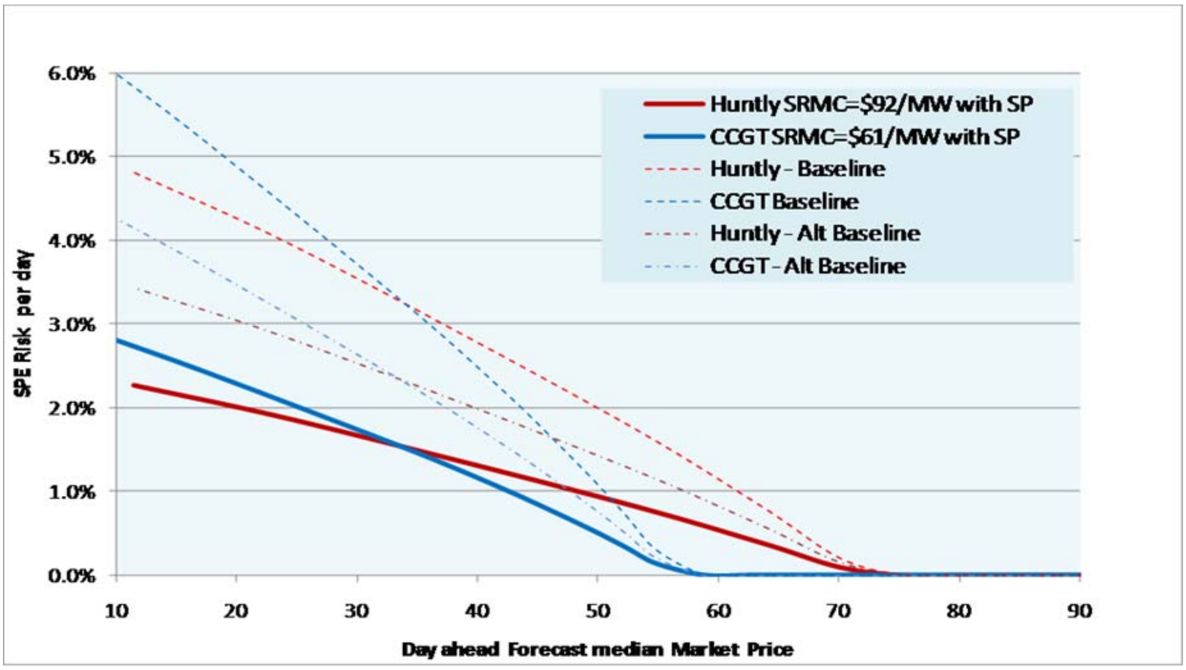
84 See www.ea.govt.nz/document/11764/download/our-work/.../21Oct10

85 This is an event where 174 MW of load shedding is required for 3 hours. An event of this type would result in a social cost of \$5 million if it occurs, which is calculated as 174 MW x 3 hrs x (10,000 MWh - \$350/MWh). The last term represents the difference between the average cost of load shedding and the avoided cost of generation assuming it is oil-fired.

86 Further detail on this analysis is available in spreadsheet form from the Authority website.

Figure 12: Required likelihood of SPE for unit commitment decision to break even



B.32 It is estimated that unit commitment risk is a potential issue for around 40 days per annum[87]. This means that the introduction of scarcity pricing could reduce the risk of SPE events arising from inadequate unit commitment by between 0.4 and 0.8 per events annum. This corresponds to an annual expected benefit of \$1.8 million to \$3.9 million per year[88].

B.33 The unit commitment benefit is assumed to accrue most significantly in the early years of the analysis, when the capacity margin is expected to be above the long term average and hence the unit commitment risk is higher. The analysis assumes that this risk declines over time, and the unit commitment benefit is therefore phased down from 2016 to 50% of the initial level by 2022.

B.34 In present value terms, this equates to \$14 million - \$31 million.

Scarcity pricing – demand-side response benefit

B.35 As noted earlier, suppression of spot prices during load shedding will reduce the scope for voluntary price-based demand response. For example, a demand-side provider with a \$2,000/MWh variable cost would need to have fixed costs of

87 This is assumes that forecast spot prices have a lognormal distribution with a mean of \$90/MWh (based on hedge forecasts) with a volatility of 45% (consistent with the average over the last five years).

88 As noted, each SPE event has a social cost of \$5.0m, based on 3 hours of an average 174MW shortfall at an equivalent cost of (\$10,000-\$350)/MWh.

$46/kW/year or less to be commercially viable in the baseline case[89]. This compares with a breakeven level of $88/kW/year under the scarcity pricing case. On this basis, the introduction of scarcity pricing would be expected to make a greater volume of voluntary demand response initiatives commercially viable.

B.36 This analysis assumes that 50-100 MW of such initiatives become commercially viable through the introduction of scarcity pricing. This quantum is estimated by reference to the volume of demand response offered to Transpower for its Demand-side Participation Pilot in the upper South Island[90].

B.37 Assuming that the average fixed cost of this resource is half way between the breakeven points noted in paragraph B.35 (i.e. $67/kW/year), the annual benefit would be $1.1 - $2.1 million per annum depending on whether 50MW or 100MW of additional demand response is available[91]. If the benefit is assessed against the alternative baseline case, the net benefit range is $0.5 - $1.1 million per annum.

B.38 Table 10 shows the estimated benefits in net present value terms from increased voluntary demand response arising from scarcity pricing. While these estimates are subject to a significant degree of uncertainty, they indicate that this component of scarcity pricing benefit could be material.

Table 10: Net present value of increased demand response

$m net benefit	Baseline case	Alternative baseline case
50 MW of demand response	$11.8	$ 5.6
100 MW of demand response	$23.6	$ 11.2

Scarcity pricing – expected costs

B.39 The main expected cost associated with scarcity pricing is the software changes required to the market clearing engine. No firm estimate is currently available for this cost. For the purposes of this analysis, a one-off cost of $2.5m[92] has been assumed. In addition, an allowance of $100k per annum has been made for ongoing software maintenance from year two.

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89 This figure is computed by ‘counting’ the number of hours when it would be commercially advantageous for the demand-side provider to respond under the different pricing scenarios, and then multiplying these hours by the relevant spot price, less the variable cost of demand response.

90 In that case, Transpower was offered 50MW of demand response, of which 30MW was offered at prices between $5,000/MWh and $8,000/MWh (on a fully variable basis). This offering only covered providers in the upper South Island. In this current context, the relevant catchment is all of New Zealand, so the 30MW figure has been increased.

91 For example, the calculation for the 50 MW case is 50,000 x (67-46). The difference between $67/kW/year (average breakeven level for additional demand response) and $46/kW/year provides an estimate of the additional economic surplus that arises from accessing this voluntary demand response.

92 This estimate is lower than the $4-5m assumed in the previous consultation paper. It has been reduced because the current implementation proposal is not expected to require any significant changes to the market clearing engine (e.g. requirements for additional solves).

B.40 An allowance has also been made for costs associated with three yearly reviews of scarcity pricing parameters. This is assumed to be $500k per review, to cover any costs that are incremental due to scarcity pricing.

B.41 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.

B.42 Scarcity pricing is expected to alter electricity spot prices during shortage events. This could give rise to wealth transfers among different parties. These transfers could be between types of parties (e.g. from consumers to suppliers) and/or within stakeholder groups (e.g. from unhedged buyers to consumers that are hedged and can reduce their load). While such wealth transfers can affect the distribution of costs and benefits, they offset each other in the aggregation of total effects for New Zealand.

B.43 An issue raised in submissions on the previous consultation paper was whether this assumption was robust. In particular, it was suggested that any consequential effect on residential electricity prices would not be a transfer if it led to health impacts[93], since these costs can flow through the health system and affect school attendance etc. To the extent that there is a divergence between private costs (to consumers) and social costs (to New Zealand) from these effects, this argument may have some merit. However, it is difficult to assess the likely materiality of such effects for the following reasons:

- the previous consultation paper noted that the effect on residential prices was expected to be modest. Scenario-based modelling suggested that the impact could be between nil and 1 percent on delivered electricity prices in the medium term, depending on the load profile of a residential consumer. It is not clear whether a change of this magnitude would be sufficient to appreciably alter behaviour;
- it is important to consider the *net* effect of scarcity pricing on health costs. For example, health impacts could be expected with widespread forced load shedding. The impact could be significant given that load shedding is more likely at times of system peak (winter evenings, especially during a cold snap)[94]. For affected parties, loss of power could eliminate all heating as well as lighting and telephone communication. Likewise, other wider effects could arise during a forced load curtailment (e.g. school closures etc); and

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93 For example, from colder houses leading to more hospital admissions for cardio-pulmonary disorders.

94 The Authority has issued Guidelines on arrangements to assist Medically Dependent Consumers (MDCs). These strongly encourage MDCs to ensure that they have an emergency response plan in place to address power outages (e.g. a stand-by battery that is always fully charged). While such consumers should not be affected (assuming the guidelines have been met), other consumers could still be adversely affected. For example, the use of candles increases during power outages with a consequent increase in the risk of fire.

- even if scarcity pricing did have a significant net impact on health costs (which is far from clear), it is not obvious that rejecting scarcity pricing is the best outcome from society's overall perspective. Addressing health or affordability issues in a more direct way is likely to be more effective than seeking to address them by altering the expected level of security of supply.

B.44 In light of these factors, this analysis continues to treat effects which are purely wealth-transfers as being neutral in net economic terms.

B.45 Finally, there is the possibility that scarcity pricing could create unduly strong signals to invest in resources to avoid forced demand curtailment (i.e. inefficiently high levels of security). This cost is not included in the baseline scenario, but is considered as a sensitivity case in the next section.

Sensitivity case - price overshooting

B.46 A number of submissions on the previous consultation paper raised a concern that scarcity pricing could lead to price 'overshooting' during IR shortages or curtailment events. In particular, it was argued that the adoption of scarcity pricing might be perceived as legitimising higher prices during situations where capacity is tight but load shedding is not required. This could result in an inefficiently high level of security with net economic costs.

B.47 These concerns should be reduced by changes made to the scarcity pricing proposal since the previous consultation paper. In particular, the adoption of a scarcity price floor/cap mechanism (rather than a floor) and the stop-loss mechanism to limit the application of scarcity pricing should reduce the likelihood of overshooting during load shedding.

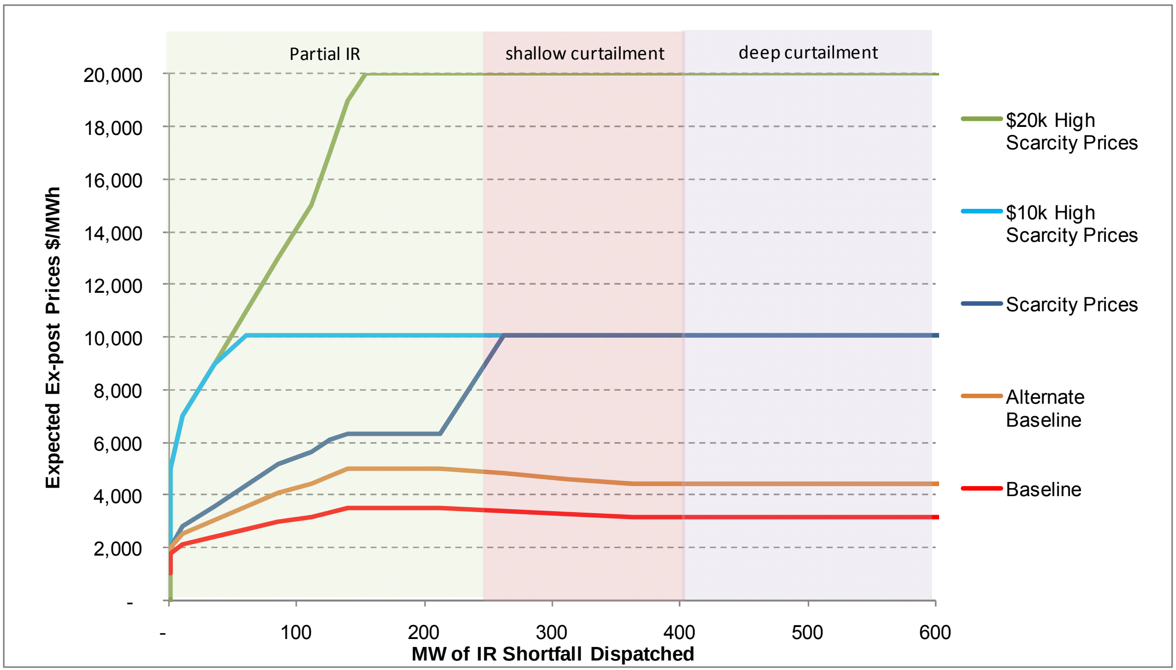
B.48 Notwithstanding these changes, some price 'overshooting' scenarios have been analysed to assess their potential effects. They are:

- Scenario A - spot prices are assumed to rise to $10,000/MWh for shortfalls of 60MW or above; and
- Scenario B - where spot prices are higher and settle at $20,000/MWh[95] in larger IR shortfalls and load shedding situations.

B.49 These cases are shown in Figure 13.

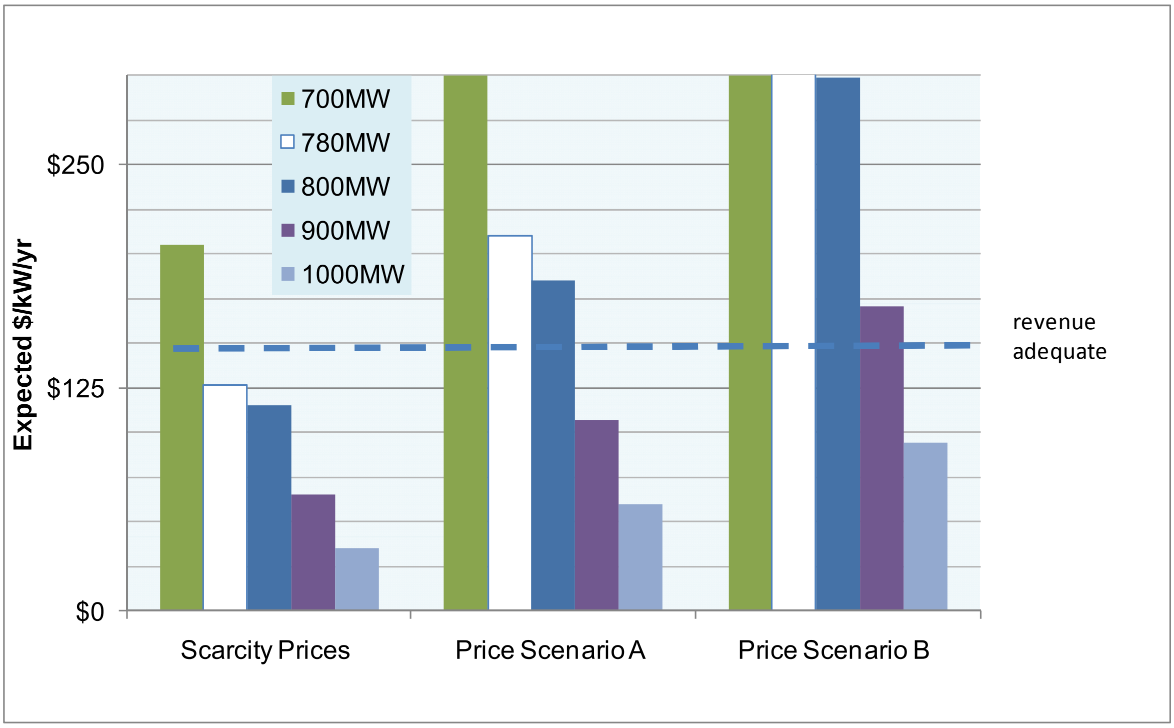
[95] This outcome is not expected if the scarcity price floor is set at $10,000/MWh and the cap is set at $20,000/MWh, as competition for dispatch is expected to moderate prices in modest/medium IR shortfalls. However, the scenario cannot be ruled out and has been included for completeness.

Figure 13: Price 'overshooting' scenarios



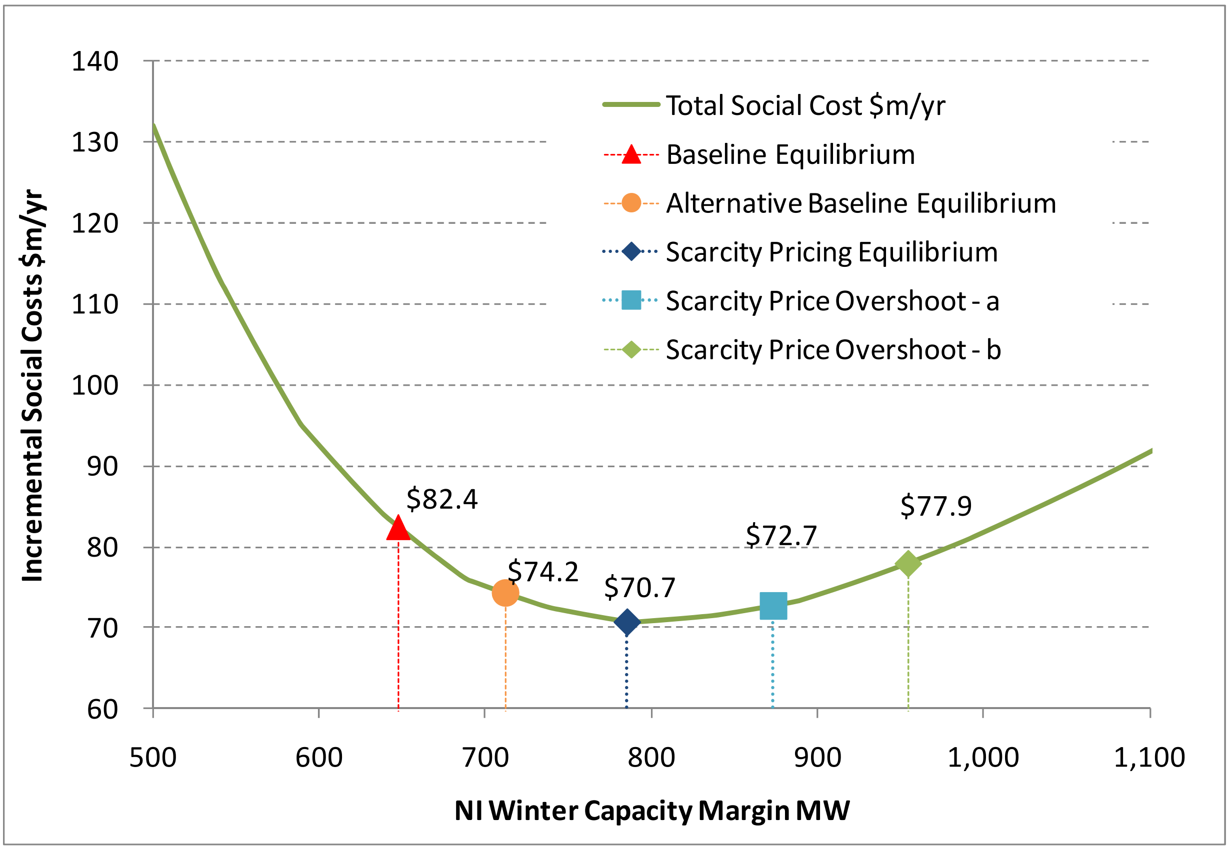
B.50 The effect of these price scenarios on revenue for a last resort provider is shown in Figure 14. In these cases, a last resort provider would earn more than its costs if the capacity margin was at the 780MW standard, indicating that further investment in last resort plant would be expected until a new equilibrium is established.

Figure 14: Expected revenue for last resort provider – price overshooting scenario



B.51 The expected new equilibrium points under the two price scenarios are shown in Figure 15.

Figure 15: Combined cost of non-supply and supply – price 'overshooting' scenarios



B.52 In the case of scenario A, the equilibrium capacity margin[96] is around 870MW and there is more investment in last resort resources than is optimal from a national perspective. As a result, the estimated incremental system cost is $2 million per year higher than optimal[97]. While this outcome would be sub-optimal relative to the ideal, it would still be a significant improvement when compared to the baseline scenario. It would also be an improvement compared to the alternative baseline scenario, although the gain is much more modest in this case.

B.53 In the case of scenario B, the equilibrium capacity margin is around 950MW. In this case, the estimated incremental system cost is $7.2 million per year higher than optimal[98]. Again, it would be an improvement relative to the baseline case, but would be worse than the alternative baseline case.

B.54 In summary, this analysis suggests that even if some price 'overshooting' did occur during shortages, it is unlikely to erode the expected investment benefits of scarcity

[96] The point where the commercial return from investment in last resort capacity = the incremental cost of capacity.

[97] This is the difference between the $72.7m (price overshoot scenario) and $70.7m (optimal case).

[98] This is the difference between the $77.9m (price overshoot scenario) and $70.7m (optimal case).

pricing relative to the baseline case[99]. If scarcity pricing is assessed against the alternative baseline case (with less initial price suppression), the net benefit position is less clear cut. With modest overshooting, a net benefit would be expected, but this would reverse if there was significant price overshooting (e.g. prices rising to $20,000/MWh in modest IR shortfalls and all demand curtailment situations).

B.55 However, it is important to note that the analysis set out above assumes that price 'over-shooting' is sustained, and that average spot prices are persistently above the level needed to provide revenue adequacy for a last resort provider when the system is at the capacity standard.

B.56 This might occur if the scarcity pricing regime *administered* prices to the 'overshooting' levels shown in Figure 13. However, the proposed regime would not do this. Rather, it would provide a GWAP floor at $10,000/MWh which only applies in widespread forced load shedding. Prices during load shedding could only settle above this level on a persistent basis if suppliers persistently offered at higher prices (and a scarcity cap value above $10,000/MWh was applied).

B.57 However, absent conditions of highly localised market power, suppliers cannot generally predict market conditions with certainty. As a result, by increasing their offer prices, suppliers will reduce the likelihood of being dispatched. They would also increase the likelihood of other competitive responses, such as increased price-based demand response or the entry of new generation. In short, based on the proposed scarcity price mechanism, it appears unlikely that material price overshooting would occur on a sustained basis.

Other sensitivity cases

B.58 The analysis set out above is based on an assumed oil-fired peaker with a variable cost of $350/MWh, annual fixed operating and capital recovery costs of $145/kW per year, and $20/kW per year of costs covered during "energy" shortfalls.

B.59 Table 11 shows how the results would vary under a range of different assumptions for these factors.

99 This is because the economic costs of capacity shortfalls and surpluses are not symmetric. For any given MW divergence from the optimal level, a shortfall is expected to be more costly than a surplus margin. This arises because the cost of carrying too much resource increases according to a linear function with capacity, whereas the cost of shortfalls is non-linear and tends to rise exponentially with declining capacity margin.

Table 11: Sensitivity Analysis

			Equilibrium Benefit of Scarcity Pricing relative to Baseline $m/yr		
Parameter	Base Case	Sensitivity	Low	Mid	High
Peaker Capital Costs $/kW/yr	$145	-/+25%	$7.4	$11.7	$15.4
Peaker Fuel Costs $/MWh	$350	-/+25%	$11.1	$11.7	$12.4
Revenue earned from dry-year $/kW/yr	$20	+/-$20/kW/yr	$8.9	$11.7	$13.9

B.60 The equilibrium benefit from introducing scarcity pricing would be up to $1-3 million per year higher if peaker fuel or capital costs were 25% higher than expected, or if the revenue earned during dry years was $20/kW per year lower.

B.61 The benefit would be $1-4 million per year lower if peaker fuel or capital costs were 25% lower, or if the revenue earned during dry years were higher.

B.62 The sensitivity analysis indicates that changes in external factors are less important than the choice of pricing scenario against which to assess scarcity pricing. For this reason, the Alternative Baseline scenario has been used for the purposes of compiling the low estimates for the overall net benefit range.

Scarcity pricing – overall costs and benefits

B.63 Table 12 summarises the results of applying the assumptions set out above.

Table 12: Scarcity pricing estimated costs and benefits

$m NPV	**Lower**	**Higher**
Costs		
Implementation costs	(5)	(5)
3 yearly reviews	(2)	(2)
Total	(7)	(7)
Benefits		
Investment signalling	27	92
Unit commitment	14	30
Additional demand response	6	24
	47	145
Net benefits	40	138
Ratio of benefits : costs	6.7	20.8

B.64 In summary, scarcity pricing is expected to yield net benefits of around $40-138 million in present value terms.

B.65 The key driver for this range is the degree to which spot prices are suppressed during shortages in the absence of scarcity pricing. If spot prices settle at the highest generator offers observed until 2010 (i.e. around $3,500/MWh), the expected net benefit would be toward the upper end of the range. On the other hand, if spot prices settle at around $5,000/MWh in shortages[100], then expected net benefits would be toward to the lower end of the range. However, in either case, a strong benefit/cost ratio is evident.

B.66 For completeness, it is important to acknowledge the possibility that no spot price suppression will occur in the absence of scarcity pricing. In that case, no direct benefit would accrue from scarcity pricing.

B.67 However, even if this were the case, adopting scarcity pricing could be preferable to the status quo. The reason for this view is that scarcity pricing has a relatively modest cost (around $7 million NPV), but provides insurance against outcomes which although uncertain in magnitude, could be much more costly (i.e. $47 – 146 million in NPV terms).

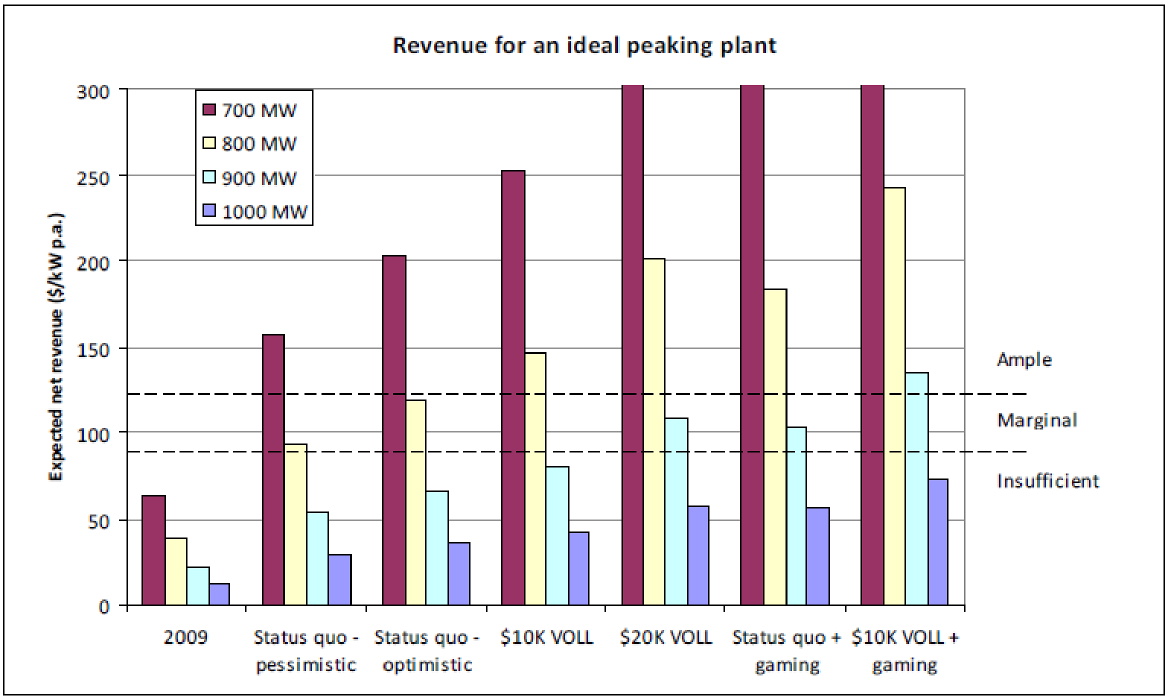
Scarcity pricing - reconciliation with October 2010 paper

B.68 This section comments on differences between the cost benefit analysis and an earlier paper prepared for the Scarcity Pricing Technical Group (SPDBTG)[101] in October 2010. The SDBTG paper included the chart shown as Figure 16.

[100] Bearing in mind that the reserve energy scheme and administered capacity offer price for Whirinaki will cease upon sale of that plant.

[101] ‘Price effects of Scarcity Pricing’, Paper for Scarcity Pricing and Default Buyback Technical Group, October 2010, Electricity Commission. See www.ea.govt.nz/document/11757/download/our-work/.../21Oct10/

Figure 16: Chart from October 2010 paper on pricing effects



B.69 The chart indicates that the "status quo - optimistic" scenario would provide adequate revenue for a last resort plant if the system has an 800MW capacity margin. This is different to the expected outcome in the cost benefit analysis, where price suppression under the 'Baseline' and 'Alternative Baseline' cases is expected to result in insufficient revenue to justify investment in a last resort plant if the system margin is at 780MW (see Figure 9 above).

B.70 The key reasons for the differences are set out in Table 13[102].

Table 13: Key differences in assumptions between October 2010 paper and CBA

Issue	October 2010 paper	Cost benefit analysis	Comment
Fixed cost of last resort plant	$125/kW/yr	$145/kW/yr	CBA reflects current estimates. SPDBTG paper noted that $125/kW/yr figure "is probably an underestimate" and "should be considered to be a lower bound"[103].

[102] There are other differences, but they appear to have a less material impact on the overall results.

[103] See footnote 6 of October 2010 paper. The revised cost estimate was included in papers presented to the SPTG in February 2011.

Revenue outside IR shortfalls and load shedding	$38.5/kW/yr [104]	$20/kW/yr	October paper and CBA both assume $20/kW/yr for 'dry year' revenues[105]. October paper assumes a further $18.5/kW/yr from periods outside IR curtailment or load shedding (versus nil for CBA). While a peaker might earn other revenue at times other than IR shortage or load curtailment, the CBA focuses on expected revenue for a *last resort* plant. By definition, such a plant cannot rely on any revenue from this source[106]. The assumption of nil revenue outside of shortage periods appears to be consistent with the stance adopted by the Australian Energy Market Commission in setting scarcity prices.

B.71 If the analysis in October 2010 is updated to reflect these differences, the revised results are consistent with the cost benefit analysis in this appendix. Figure 17 shows the original results from the October 2010 paper for a last resort plant based on a capacity margin of 800MW. In this case, the last resort plant achieves revenue adequacy under the two "status quo" cases and earns more than its costs in the "$10k VOLL" case.

B.72 The right hand chart shows the effect of adjusting the expected peaker cost upwards by $20/kW/year (to reflect more recent data) and reducing peaker revenue by $18.5kW/year (to reflect view that a last resort plant cannot rely on revenue during non-shortage times). With these revisions, the last resort plant does not achieve revenue adequacy under either of the two "status quo" cases, and only earns sufficient revenue to cover its costs in the "$10k VOLL" case.

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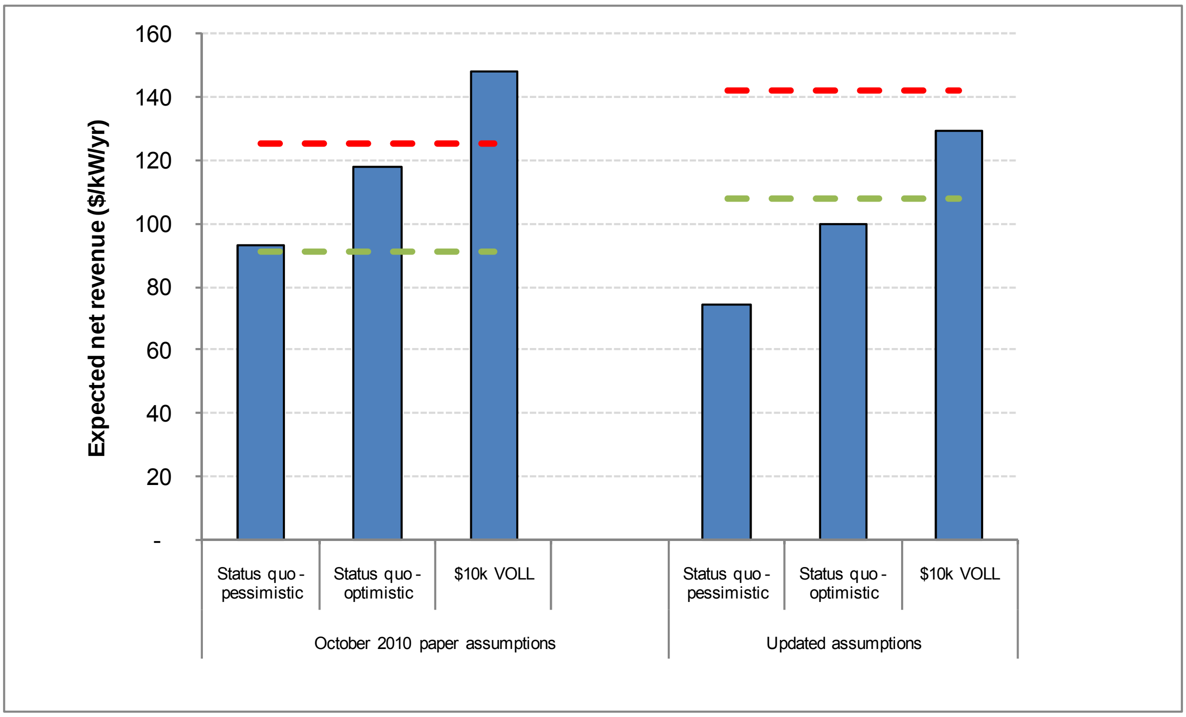
104 See 'near miss' column in Table below paragraph 2.4.2 of October 2010 paper.

105 See paragraph 2.4.9 of October 2010 paper.

106 By definition, a last resort plant is not expected to be dispatched when the system has sufficient resource to meet demand and maintain a full reserve requirement. SPDBTG discussed this issue in July 2010, and the nil revenue approach outside of shortages was adopted for estimating scarcity price values.

Figure 17: Effect of updating October 2010 paper analysis



Cost benefit analysis of stress testing regime

B.73 The proposed stress testing regime will require certain parties to report information to the Authority. However, parties will remain responsible for their own risk management decisions, and the consequences of those decisions.

Costs of stress testing regime

B.74 The costs of the stress testing regime fall into two broad categories:

- initial implementation costs for both the Authority and relevant parties covered by the regime; and
- ongoing operational costs for participants in preparing reports and for the Authority in reviewing this material and publishing summarised information.

B.75 Because the regime will not create any binding obligations on parties (other than to report information), it is not expected that the regime will give rise to other economic costs.

B.76 The estimated costs for the Authority are $100k to implement the regime, and $50k per year for operation. Both of these estimates are for *incremental* costs, noting that the Authority has already developed a proposed design for the regime, and will be undertaking some monitoring work irrespective of whether the stress test regime per se is introduced.

B.77 The proposed stress test regime has been designed to 'piggy-back' on participants' existing internal risk analysis processes as far as possible. It will require parties to compute the effect on their financial position of applying certain pre-defined tests using their own risk analysis systems, and report the result to the Authority. For this reason, it is not expected that parties will need to develop any significant new systems or processes[107].

B.78 The incremental costs for each participant have been estimated at $24k for implementation and $11k per year for ongoing costs[108]. These are weighted averages, and the costs are expected to be higher for larger parties with more complex businesses, and lower for smaller/less complex businesses. It is assumed that 25 reporting entities will be subject to the obligation.

B.79 A higher cost scenario has also been included where costs are 50% higher than the base case, and 40 participants are subject to the regime.

B.80 The net present value of costs based on these assumptions is shown in Table 14.

Table 14: Stress-test regime cost estimates

NPV of costs at 8% real discount rate		Basecase scenario	Higher cost scenario
Electricity Authority - implementation	$m	0.1	0.2
Electricity Authority - ongoing	$m	0.6	0.8
Participants - implementation	$m	0.6	1.4
Participants - ongoing	$m	3.1	7.5
Total cost		4.4	10.0
Total cost (levelised annual equivalent)	$k/year	361	819

Benefits of stress testing regime

B.81 The expected benefits of the stress testing regime include:

- reducing the damage to broader economic confidence that arises from parties 'talking up' the level of security risk when the system is tight. Parties can make very damaging claims about market effectiveness and competitiveness during periods of system stress in an effort to reduce spot prices. This 'talking up' of risks has ongoing negative effects, as perceptions about electricity security and competitiveness have a direct influence on New Zealand's attractiveness as a place to invest and do business;
- reducing the expected frequency of public conservation campaigns, by making it harder for parties to lobby for early use of campaigns without revealing their financial motivation;
- strengthening incentives for parties to prudently manage their exposures to spot price risk, with flow-on benefits in terms of more procurement of voluntary

107 If participants have to invest additional resources in risk analysis processes, this would be expected to also provide internal benefits to those parties.

108 This equates to around 4-5 person weeks of resource for implementation, and 2-3 weeks per year for operation.

demand-side response, improved fuel management, investment/retention of energy reserve capability etc;

- providing information to the Authority on the extent of systemic exposure to spot price risk in the wholesale market (which can inform decisions around matters such as the transitional stop-loss mechanism); and
- providing information to assist the Authority in fulfilling its broader market monitoring functions under section 16 of the Electricity Industry Act.

B.82 These benefits overlap in some areas and it is difficult to quantify them based on a 'bottom-up' approach. Instead, this analysis proceeds by asking 'what degree of improvement' would be required to breakeven in overall economic terms, given the cost estimates noted earlier. It then considers whether the required change appears plausible or not.

278. The primary benefit of the stress testing regime is expected to be stronger economic growth due to greater confidence in security of supply. If this was the sole benefit, gross domestic product (GDP) would need to be higher by 1/2000th to 1/5000th of one percent per year for the regime to yield net benefits. This is an extremely small improvement, and given the important role that electricity plays in almost every sector of the economy, this change would appear to be well within the plausible range.

279. The likelihood of net benefits has also been assessed assuming that there is no improvement in wider economic growth. Instead, it identifies the change in public conservation campaign frequency that would be required to obtain net benefits. The analysis is based on the following assumptions:

- society incurs a cost of $93 million if a public conservation campaign occurs, comprising losses of consumption by residential users, and advertising and publicity costs. The $93 million estimate is based on the assumptions adopted for the Customer Compensation Scheme cost benefit analysis undertaken in 2010[109]; and
- the expected return period for public conservation campaigns is 10 years *in the absence of a stress testing regime*. This estimate is based on the assumed return period if a Customer Compensation Scheme is in operation[110].

B.83 These assumptions are used to estimate the change in the public conservation campaign return period required to make the stress testing regime worthwhile, assuming it is the sole benefit from this initiative. The main elements of the calculation are shown in Table 15.

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109 See pp.67-86 of 'Customer Compensation Schemes', Consultation Paper, Electricity Commission, October 2010.

110 See p.67 of 'Customer Compensation Schemes', Consultation Paper, Electricity Commission, October 2010. The 8-10 years was the assumption with the customer compensation scheme in place, and five years was assumed in the base case without the scheme.

Table 15: Stress-test regime – calculation of required benefits and PCC return period

		Basecase	Higher cost scenario
Levelised cost of stress-test regime	$k/year	361	819
Expected annual cost of PCC - no stress-test regime	$k/year	9,300	9,300
Reduction in expected PCC cost for CBA to breakeven	$k/year	(361)	(819)
New level of expected PCC cost to breakeven	$k/year	8,939	8,481
Return period for PCC required to breakeven	years	10.4	11.0
Change in PCC return period to breakeven		0.4	1.0

B.84 This analysis indicates that if the expected return period for public conservation campaigns was increased from 10 years to 10.4 years, this would be sufficient to offset the estimated costs of the stress testing regime[111]. This is an extremely small change in return period (less than six months) and would be well within the plausible range of outcomes that might be expected.

B.85 If the cost of the stress test regime is at the higher estimate[112], the required change in return period is one year (i.e. public conservation campaigns would need to move out to 1 in 11 years or more for society to breakeven). Again, this would appear to be well within the plausible range of outcomes that could arise from the introduction of the stress testing regime.

B.86 A further sensitivity test has also been applied assuming that public conservation campaigns have an 18 year return period *without* a stress testing regime. The required increase in the return period to break even is still relatively modest, moving from 18 years to 19.4 or 21.4 years respectively, depending on the costs assumed for the stress test regime.

B.87 In summary, even a very modest reduction in the frequency of public conservation campaigns would provide sufficient benefits to offset the cost estimates for a stress testing regime set out in Table 14. For example, if public conservation campaigns occur every ten years on average, the return period only needs to be increased by 6 -12 months for the stress testing regime to be worthwhile.

B.88 In conclusion, based on the assumptions and analysis set out above, it is considered highly likely that the proposed stress testing regime would have positive net benefits from an economic perspective.

111 In the basecase this is $4.4m in present value terms, or a levelised cost of $363k per year

112 In this case, $10.0m in present value terms, or a levelised cost of $821k per year

Appendix C Draft amendments to Code

Proposed amendments to Part 1 of the Code

base case means a base case **publicised** by the **Authority** under clause 13.236B

disclosing participant means any of the following:
(a) a **generator**:
(b) a **retailer**:
(c) a person who consumes **electricity** that is conveyed to the person directly from the national **grid**:
(d) a person who buys **electricity** from the **clearing manager**.

island GWAP means the generation weighted average price for an **island** calculated in accordance with clause 1(2) of Schedule 13.3A

island scarcity pricing situation means a situation determined to be an island scarcity pricing situation by the **pricing manager** under clause 13.135A(3)

island shortage situation means a situation specified in a notice to be an island shortage situation by the **system operator** under clause 7(20C) of **Technical Code** B of Schedule 8.3

national GWAP means the generation weighted average price for both **islands** calculated in accordance with clause 2(2) of Schedule 13.3A

national scarcity pricing situation means a situation determined to be a national scarcity pricing situation by the **pricing manager** under clause 13.135A(4)

national shortage situation means a situation specified in a notice to be a national shortage situation by the **system operator** under clause 7(20D) of **Technical Code** B of Schedule 8.3

shortage situation means an **island shortage situation** or a **national shortage situation**

risk disclosure statement means a risk disclosure statement prepared and submitted under clause 13.236A

scarcity pricing situation means an **island scarcity pricing situation** or a **national scarcity pricing situation**

stress test means a stress test **publicised** by the **Authority** under clause 13.236B

Proposed amendments to Technical Code B of Schedule 8.3 of the Code

7 Load shedding systems

(1) Each North Island **distributor** must ensure, at all times, that an **automatic under-frequency load shedding** system is installed in accordance with subclause (6) for each **grid exit point** to which its **local network** is connected.

(2) Every South Island **grid owner** must ensure, at all times, that an **automatic under-frequency load shedding** system is installed in accordance with subclause (6) for each **grid exit point** in the South Island.

(3) Subject to subclause (8), each **distributor** and **grid owner** must use reasonable endeavours to ensure that at all times its **automatic under-frequency load shedding** systems are maintained in accordance with subclause (6).

(4) If, at any time, a **distributor** or **grid owner** believes that an **automatic under-frequency load shedding** system may not be capable of meeting the requirements of subclause (6), it must notify the **system operator** as soon as practicable and provide any information that the **system operator** reasonably requests.

(5) Each South Island **distributor** must co-operate fully with any **grid owner** in relation to an **automatic under-frequency load shedding** system installed at any **GXPs** at which the **distributor's local network** is connected to the **grid**. Each South Island **distributor** must also provide the **grid owner** with any information relating to **automatic under-frequency load shedding** that the **grid owner** reasonably requests.

(6) An **automatic under-frequency load shedding** system required to be provided in accordance with subclause (1), must enable, at all times, automatic disconnection of 2 blocks of **demand** (each block being a minimum of 16% of the total pre-event **demand**) at that **grid exit point** subject to subclause (8), with block one disconnecting **demand—**

(a) in the North Island, within 0.4 seconds after the frequency reduces to, and remains at or below, 47.8 Hertz; and

(b) in the South Island, within 0.4 seconds after the frequency reduces to, and remains at or below 47.5 Hertz;

and block two disconnecting **demand—**

(c) in the North Island,**—**

(i) 15 seconds after the frequency reduces to, and remains at or below, 47.8 Hertz; or

(ii) within 0.4 seconds after the frequency reduces to, and remains at or below, 47.5 Hertz; and

(d) in the South Island,—
  (i) 15 seconds after the frequency reduces to, and remains at or below, 47.5 Hertz; or
  (ii) within 0.4 seconds after the frequency reduces to, and remains at or below, 45.5 Hertz.

(7) To avoid doubt, **automatic under-frequency load shedding** blocks must not include any **interruptible load** procured by the **system operator**.

(8) Subject to the **system operator's** agreement, which must not be unreasonably withheld, a **distributor** or a **grid owner** may redistribute **automatic under-frequency load shedding** quantities between **grid exit points**, if the overall **automatic under-frequency load shedding** quantity obligations in subclause (6) are met.

(9) Each **distributor** and each **grid owner** must provide **automatic under-frequency load shedding** block **demand** profile information to the **system operator** if reasonably requested by the **system operator**. That information must be in a form that enables the **system operator** to make a reasonable assessment of the total amount of **demand** available to be disconnected if **automatic under-frequency load shedding** blocks operate in accordance with subclauses (6) to (8).

(10) Subclauses (12) to (16) apply if a direction under clause 9.15 is in force.

(11) When subclauses (12) to (16) apply, the **system operator** may give notice to 1 or more of the **participants** specified in subclause (14), specifying modifications to the extent to which subclauses (1) to (4) and (6) apply to the **participant** during any 1 or more periods, or in any 1 or more circumstances, specified in the notice.

(12) The **system operator** must keep a record of each notice given under subclause (11).

(13) When a notice under subclause (11) is in force in relation to a **participant**, the requirements of subclauses (1) to (4) and (6) are modified for that **participant** to the extent, and during the periods or in the circumstances (as the case may be), specified in the notice.

(14) The **participants** to whom the **system operator** may issue a notice in accordance with subclause (11) are—
  (a) **distributors** in the North Island; and
  (b) **grid owners** in the South Island.

(15) The **system operator** may amend or revoke a notice, or revoke and substitute a new notice.

(16) A notice under subclause (11) expires on the earlier of—
  (a) the date (if any) specified in the notice for its expiry; or

(b) the revocation or expiry of the direction referred to in subclause (10).

(17) The **system operator**, each **distributor**, each **grid owner** and relevant **retailers** must co-operate, if reasonably practicable, to ensure that any **interruptible load** contracted by the **system operator** that could affect the size of an **automatic under-frequency load shedding** block is identified to assist the **distributor** or the **grid owner** to meet its obligations in subclauses (5) to (9).

(18) On the operation of an **automatic under-frequency load shedding** system, the **distributor** or **grid owner—**

(a) must, as soon as practicable, advise the **system operator** of the operation of the **automatic under-frequency load shedding** system and, if reasonably required by the **system operator** to plan to comply, or to comply, with its **principal performance obligations**, a reasonable estimate of the amount of **demand** that has been disconnected; and

(b) may restore **demand** only when permitted to do so by the **system operator**; and

(c) must ensure **demand** restored in accordance with paragraph (b) complies with subclause (6); and

(d) must report to the **system operator** if **demand** is moved between **points of connection**; and

(e) may request permission to restore **demand** from the **system operator** if no instruction to restore **demand** is received from the **system operator** within 15 minutes of the frequency returning to the **normal band**; and

(f) may cautiously and gradually restore the **demand** disconnected through the **automatic under-frequency load shedding** system if there is a **loss of communication**, after 15 minutes of the **loss of communication** occurring. This restoration must be done only while the frequency is within the **normal band** and the voltage is within the required range. Each **distributor** must immediately cease the restoration of **demand** and, to the extent necessary, disconnect **demand**, if the frequency drops below the **normal band** or the voltage moves outside the required range. As soon as practicable after communications are restored, each **distributor** or each **grid owner** must report to the **system operator** on the status of load restoration and the status of re-arming the automatic under-frequency relays.

(19) Each **distributor** must maintain an up to date process for the disconnection of **demand** for **points of connection**, including the specification of the **participant** who will

effect the disconnection of **demand**. The **distributor** must obtain agreement for the process from the **system operator** and each **grid owner** (such agreement not to be unreasonably withheld). Each **distributor** must advise the **system operator** of the agreed process in addition to any changes to a process previously advised.

(20) If the **system operator** requires the disconnection of **demand** in accordance with this **technical code**, the **system operator** must instruct **distributors** and **grid owners** (as the case may be) in accordance with the agreed process in subclause (19) to disconnect **demand** for the relevant **point of connection**. If the **system operator** and a **distributor** or **grid owner** (as the case may be) have not agreed on a process for disconnection of **demand** at a **point of connection**, the **system operator** must instruct **grid owners** to disconnect **demand** directly at the relevant **point of connection**. To the extent practicable, the **system operator** must use reasonable endeavours when instructing the disconnection of **demand**, to ensure equity between **distributors**.

(20A) If the **system operator** requires the disconnection of **demand** under clause 6(1)(d) or clause 6(2)(d), or amends or revokes an instruction to disconnect **demand**, the **system operator** must, as soon as practicable, **publish** the following:

(a) a notice of the instruction to disconnect **demand** that sets out all details of the instruction:

(b) a notice of the amendment or revocation of the instruction to disconnect **demand** that sets out all details of the amendment or revocation.

(20B) The **system operator** must log and record all instructions to disconnect **demand** that are issued, amended, or revoked in a **trading day** and provide the record to the **pricing manager** by 0730 hours on the following **trading day**.

(20C) The **system operator** must, as soon as practicable, **publish** notice of an **island shortage situation** if—

(a) the **system operator** requires the disconnection of **demand** under clause 6(1)(d); and

(b) in the **trading period** in which the disconnection of **demand** is required—

(i) there is no **binding constraint** in an **island** (excluding the **HVDC link**) in which the **demand** is required to be disconnected; and

(ii) there is a **binding constraint** on the **HVDC link** or the **HVDC link** is out of service.

(20D) The **system operator** must, as soon as practicable, **publish** notice of a **national shortage situation** if—

(a) the **system operator** requires the disconnection of **demand** under clause 6(1)(d); and

(b) in the **trading period** in which the disconnection of

demand is required—

(i) there is no **binding constraint** in either **island**; and

(ii) the **HVDC link** is in service and there is no **binding constraint** on the **HVDC link**.

(20E) The **system operator** must—

(a) revoke a notice of a **shortage situation** when the instruction to disconnect **demand** is revoked; and

(b) **publish** notice of the revocation as soon as practicable after the notice is revoked.

(20F) The **system operator** must provide a notice **published** under subclause (20C), subclause (20D), or subclause (20E) in a **trading day** to the **pricing manager** by 0730 hours on the following **trading day**.

(21) Each **distributor** or **grid owner** must act as instructed by the **system operator** operating in accordance with clauses 6 and 7.

Compare: Electricity Governance Rules 2003 clause 6 technical code B schedule C3 part C

Proposed amendments to Part 13 of the Code

13. 13.1 to 13.58

[No changes]

13.59 Contents of each pre-dispatch schedule [*Note: the proposed amendments to the Code relating to DSBF and dispatchable demand propose to alter this clause. If those changes are approved before the changes below, the changes may be incorporated into the amended clause 13.59. However, the proposed amendments may make the proposed paragraphs below redundant, in which case they will be removed*]

Each **pre-dispatch schedule** prepared by the **system operator** must specify, for each **trading period** in the **schedule period**,—

(a) the expected average level of **electricity** output for each **generating plant** or **generating unit**; and

(b) the expected average level of **interruptible load** and **instantaneous reserve** for each **generating plant** or **generating unit**; and

(c) the indicative **frequency keeping generating stations** for each **island** at the time of preparation of each **pre-dispatch schedule**; and

(d) the expected average level of demand at each **grid exit point**; and

(e) **forecast prices** for each **grid injection point**, each **grid exit point**, and the **reference points**; and

(f) **forecast reserve prices** for each **island**; and

(g) **forecast marginal location factors** for each **grid injection point** and each **grid exit point**; and

(h) the expected largest single reserve risk for each **island**; and

(i) the expected level of **fast instantaneous reserve** and **sustained instantaneous reserve** required in each **island**; and

(j) a stack of **reserve offers** for each **island** (ranking in price order from lowest to highest), and for each **island** separate stacks must be provided for **fast instantaneous reserve** and **sustained instantaneous reserve**; and

(k) a stack of all **reserve offers** for each **island** (ranking in price order from lowest to highest) adjusted for the expected level of energy output for each **generating plant** or **generating unit** related to the **pre-dispatch schedule**, and for each **island** separate stacks must be provided for **fast instantaneous reserve** and **sustained instantaneous reserve**; and

(l) the expected **HVDC component flows**; and

(m) the expected **HVDC risk offsets**~~.~~; and

(n) the expected deficit quantities for energy, **fast instantaneous reserve**, and **sustained instantaneous reserve** (if any); and

(o) the expected binding **transmission security constraints** in each **island**; and

(p) the expected **binding constraints** limiting the flow of **electricity** on the **HVDC link** or whether the **HVDC link** is out of service.

Compare: Electricity Governance Rules 2003 rule 3.5 section III part G

System operator to publish information

13.103 System operator responsible for co-ordinating publication

[No changes]

13.104 Information to be published [***Note: the proposed amendments to the Code relating to DSBF and dispatchable demand propose to alter this clause. If those changes are approved before the changes below, the changes may be incorporated into the amended clause 13.104. However, the proposed amendments may make the proposed paragraphs below redundant, in which case they will be removed***]

(1) When the **system operator** has completed a **pre-dispatch schedule**, the **system operator** must **publish**, for each **trading period** in the **schedule period**—

(a) the aggregate supply curve at each **reference point** incorporating all **offers** from **generators** with prices adjusted for **forecast marginal location factors**; and

(b) the aggregate demand curve at each **reference point** incorporating all **bids** from **purchasers** with prices adjusted for **forecast marginal location factors**; and

(c) the **grid injection points** and **grid exit points** that are **disconnected** and the **grid injection**

points and **grid exit points** where an **infeasibility situation** has occurred; and

(d) the expected largest single reserve risk for each **island** as prepared by the **system operator** in accordance with clause 13.59(h); and

(e) the **instantaneous reserve** levels for each **island** prepared by the **system operator** in accordance with clause 13.59(i); and

(f) the **reserve offer** stacks for each **island** prepared by the **system operator** in accordance with clause 13.59(j); and

(g) the adjusted **reserve offer** stacks for each **island** prepared by the **system operator** in accordance with clause 13.59(k); and

(h) the indicative **frequency keeping generating stations** for each **island**; and

(i) the expected **HVDC component flows**; and

(j) the expected **HVDC risk offsets**~~.~~; and

(k) the expected deficit quantities for energy, **fast instantaneous reserve**, and **sustained instantaneous reserve** (if any); and

(l) the expected binding **transmission security constraints** in each **island**; and

(m) the expected **binding constraints** limiting the flow of **electricity** on the **HVDC link** or whether the **HVDC link** is out of service.

(2) At the same time that the **system operator publishes** the information required under subclause (1), the **system operator** must—

(a) send to each **purchaser** information from the current **pre-dispatch schedule** relating to that **purchaser's** demand for the **trading periods** covered by the **schedule period**; and

(b) send to each **generator** information from the current **pre-dispatch schedule** relating to that **generator's generating plants** for the **trading periods** covered by the **schedule period**.

Compare: Electricity Governance Rules 2003 rule 10.2 section III part G

13.105 to 13.130

[No changes]

Subpart 4—Pricing

13.131 Contents of this subpart

[No changes]

13.132 Purpose of the pricing process

The purpose of the pricing process is to achieve an appropriate balance between certainty and accuracy of **final prices** and **final reserve prices** for each **trading period**. As part of the process—

(a) the **system operator**, the **pricing manager**, a **grid owner**, or a **generator** must take certain steps under this subpart if a **provisional price situation** or **shortage situation** exists; and

(b) after any **provisional price situation** is resolved, but before **publishing final prices** or **final reserve prices**, the **pricing manager** must **publish interim prices** and **interim reserve prices**; and

(c) if an **error claimant** claims that a **pricing error** has been made, the **pricing manager** must consider the claim and resolve any **pricing error** that has occurred; and

(d) the **pricing manager** must produce **final prices** and send them to the **clearing manager**, who will then use them in the clearing and settlement processes; and

(e) the **pricing manager** must produce **final reserve prices**.

Compare: Electricity Governance Rules 2003 rule 2 section V part G

13.133 Trigger ratio for high spring washer price situation

[No changes]

13.134 Methodology to resolve high spring washer price situation

[No changes]

Rules governing the preparation of provisional, interim, and final prices

13.135 Methodology used to prepare provisional, interim, and final prices

To calculate **provisional prices**, **provisional reserve prices**, **interim prices**, **interim reserve prices**, **final prices** and **final reserve prices** the **pricing manager** must use—

(a) the **input information** in clause 13.141; and

(b) the methodology in Schedule 13.3.

Compare: Electricity Governance Rules 2003 rule 3.1 section V part G

13.135A Notice of scarcity pricing situation

(1) This clause applies if the **pricing manager**, in relation to a **trading period**, gives notice in accordance with clause 13.144(1) that a **shortage situation** exists.

(2) If this clause applies, the **pricing manager** must determine whether a **scarcity pricing situation** exists in the relevant trading period.

(3) An **island scarcity pricing situation** exists if the **pricing manager** gives notice that an **island shortage situation** exists and the **input information** or revised data shows that—

(a) for the relevant **trading period**, there is no **binding constraint** in an **island** (excluding the **HVDC link**) in which an **island shortage situation** declaration is made; and

(b) for the relevant **trading period**—

(i) the **HVDC link** is in service and—

(A) if the **island** in which the **island shortage situation** declaration is made is the South Island, the price at the Benmore **node** is higher than the price at the Haywards **node**; or

(B) if the **island** in which the **island shortage situation** declaration is made is the North Island, the price at the Haywards **node** is higher than the price at the Benmore **node**; or

(ii) the **HVDC link** is out of service.

(4) A **national scarcity pricing situation** exists if the **pricing manager** gives notice that a **national shortage situation** exists and the **input information** or revised data shows that, for the relevant **trading period**,—

(a) there is no **binding constraint** in either **island**; and

(b) the **HVDC link** is in service and there is no **binding constraint** on the **HVDC link**.

(5) If the **pricing manager** determines that a **scarcity pricing situation** exists, the **pricing manager** must—

(a) **publish** notice of the **scarcity pricing situation**; and

(b) specify in the notice each **trading period** affected by the **scarcity pricing situation**; and

(c) in relation to each **trading period** affected by a **scarcity pricing situation**, specify in the notice whether the **scarcity pricing situation** is an **island scarcity pricing situation** or a **national scarcity pricing situation**.

13.135B Methodology to prepare interim prices if scarcity pricing situation exists

Subject to clause 13.135C, if a **scarcity pricing situation** exists in a **trading period**, the **pricing manager** must—

(a) calculate **interim prices** and **interim reserve prices** in the affected **island** or **islands** for that **trading period** in accordance with the methodology set out in Schedule 13.3A; and

(b) **publish interim prices** and **interim reserve prices** for the previous **trading day** by—

(i) if no **provisional price situation** is notified, 1200 hours; or

(ii) if a **provisional price situation** is notified, 2.5 hours after the **provisional price situation** is resolved.

[OPTION A – Scaled pricing:

13.135C Limitation on number of trading periods affected by a scarcity pricing situation

Clause 13.135B does not apply if there has been a **scarcity pricing situation** affecting prices in an **island** in 32 **trading periods** of the previous 336 **trading periods**.]

[OPTION B – Flat pricing:

13.135C Limitation on number of trading periods affected by a scarcity pricing situation

Clause 13.135B does not apply if the sum of the **island GWAPs** in the previous 336 **trading periods** exceeds $168,000.]

Generators to give pricing manager half-hour metering information

13.136 to 13.141

[No changes]

13.142 Pricing manager to publish interim prices unless provisional price situation or shortage situation notified

(1) The **pricing manager** must implement the process set out in clauses 13.143 to 13.185 and resolve the **provisional price** situation or **shortage situation** if, by 1000 hours on a **trading day**, 1 of the following notices has been **published** for the previous **trading day**:

(a) a notice **published** by a **grid owner**, in accordance with clause 13.143, which specifies that a **SCADA situation** exists:

(b) a notice **published** by the **pricing manager**, in accordance with clause 13.144(1), which specifies that an **infeasibility situation** or a **metering situation** or a **high spring washer price situation** or a **shortage situation** exists.

(2) However, if by 1000 hours on a **trading day** a notice specified in subclause (1) has not been **published** for the previous **trading day**, the **pricing manager** must **publish interim prices** and **interim reserve prices** for the previous **trading day** by 1200 hours.

Compare: Electricity Governance Rules 2003 rule 3.4 section V part G

13.143 Grid owners to notify SCADA situation

[No changes]

13.144 Pricing manager to give notice of infeasibility situation, metering situation, or high spring washer price situation, or shortage situation

(1) Subject to subclause (2), if the **pricing manager** receives **input information** that yields an **infeasibility situation**, or a **metering situation**, or a **high spring washer price situation**, or receives notice of a **shortage situation** in accordance with clause 7(20F) of **Technical Code** B of Schedule 8.3, the **pricing manager** must, no later than 0900 hours on the day that the **pricing manager** receives the **input information** or notice,—

(a) **publish** notice of the **infeasibility situation**, or **metering situation**, or **high spring washer price situation**, or **shortage situation**; and

(b) specify in the notice each **trading period** affected by the **infeasibility situation**, or **metering situation**, or **high spring washer price situation**, or **shortage situation**; and

(c) in relation to each **trading period** affected by a **high spring washer price situation**, specify in the notice each **transmission security constraint** that has **bound** in the relevant **trading period** or **trading periods**~~.~~; and

(d) in relation to each **trading period** affected by a **shortage situation**, specify in the notice whether the **shortage situation** is an **island shortage situation** or a **national shortage situation**.

(2) The **pricing manager** must not give notice of a **high spring washer price situation** or **shortage situation** in accordance with subclause (1) in relation to a **trading period** if an **infeasibility situation**, or a **metering situation**, or a **SCADA situation** exists in that **trading period** and has not been resolved.

Compare: Electricity Governance Rules 2003 rules 3.6 and 3.6A section V part G

13.145 Grid owner to give notice that estimated data given
[No changes]

13.146 Requirements if provisional price situation or shortage situation exists

(1) If notice is given by—

(a) a **grid owner** to the **pricing manager** of a **SCADA situation** in accordance with clause 13.143; or

(b) the **pricing manager** of a **metering situation** in accordance with clause 13.144(1); or

(c) the **pricing manager** of an **infeasibility situation** in accordance with clause 13.144(1)—

the relevant **grid owner**, and, in the case of an **infeasibility situation**, the **system operator**, must exercise reasonable endeavours to resolve the **provisional price situation** and to provide revised data to the **pricing manager**.

(2) If notice is given of a **high spring washer price situation** in accordance with clause 13.144(1), the **system operator** must apply the **high spring washer price relaxation factor** in accordance with the **high spring washer price situation methodology** and provide revised data to the **pricing manager**.

(2A) If notice is given of a **shortage situation** in accordance with clause 13.144(1), the **pricing manager** must determine whether a **scarcity pricing situation** exists in accordance with clause 13.135A and, if a **scarcity pricing situation** does exist, calculate **interim prices** and **interim reserve prices** in accordance with clause 13.135B.

(3) The revised data required by subclauses (1) and (2) must be provided to the **pricing manager**—

(a) if the **provisional price situation** arose on a **business day**, by 1000 hours on that day; and

(b) if the **provisional price situation** arose on a day other than a **business day**, by 1200 hours on the 2nd **business day** after the **provisional price situation** arose.

(4) If a **generator** does not supply **half-hourly metering information** to the **pricing manager** or to a **grid owner** in accordance with clauses 13.136 to 13.140, and the **pricing manager** has notified a **metering situation** in accordance with clause 13.144(1), the **generator** must use reasonable endeavours to assist the **grid owner** to resolve the **provisional price situation**.

Compare: Electricity Governance Rules 2003 rule 3.8 section V part G

13.147 to 13.166

[No changes]

13.166A Pricing manager to recalculate and publish interim prices if infeasibility situation caused by a shortage of instantaneous reserve

(1) If an **infeasibility situation** that has been resolved under this subpart was caused by a shortage of **instantaneous reserve**, the **pricing manager** must recalculate and **publish interim prices** for the relevant **trading period** by adding a virtual provider of **fast instantaneous reserve** and **sustained instantaneous reserve**, at the price as specified in subclause (2), that provides sufficient **fast instantaneous reserve** and **sustained instantaneous reserve** so that prices for **fast instantaneous reserve** and **sustained instantaneous reserve** do not exceed that greatest price.

(2) The price referred to in subclause (1) for a **trading period** is the greater of—

(a) the highest **offer** scheduled in the relevant **island** during the **trading period** according to the revised data provided to the **pricing manager** under this subpart; or

(b) the highest **reserve offer** scheduled in the relevant **island** during the **trading period** according to the revised data provided to the **pricing manager** under this subpart.

Interim pricing period

13.167 to 13.182

[No changes]

Publication of final prices

13.183 to 13.185

[No changes]

Miscellaneous requirements relating to calculation of prices

13.186 to 13.191

[No changes]

Calculation of constrained off amounts

13.192 to 13.201

[No changes]

Calculation of constrained on amounts

13.202 Constrained on situations may occur

(1) Subject to subclause (2), a~~A~~ **constrained on situation** occurs when—

(a) a **generator** is given a **dispatch instruction** by the **system operator** and the price **offered** by the **generator** for that dispatched quantity of **electricity** at the relevant **grid injection point** and **trading period** is higher than the **final price** at that **grid injection point** in the relevant **trading period**; or

(b) in relation to a **block dispatch group** or **station dispatch group**, a **generator** is given a **dispatch instruction** by the **system operator** and the price **offered** by the **generator** for that aggregate dispatched quantity of **electricity** from that **block dispatch group** or **station dispatch group** in the relevant **trading period** is higher than the **final price** in the relevant **trading period**; or

(c) an **ancillary service agent** is given a **dispatch instruction** by the **system operator** and the price **offered** by the **ancillary service agent** for the dispatched **instantaneous reserve** in the relevant **trading period** is higher than the **final reserve price** of the dispatched **instantaneous reserve** in the relevant **trading period**.

(2) If a **scarcity pricing situation** occurs in a **trading period**, a **constrained on situation** is deemed not to have occurred in that **trading period**.

Compare: Electricity Governance Rules 2003 rule 5.1 section V part G

13.203 to 13.212

[No changes]

Pricing manager's reporting obligations

13.213 to 13.216

[No changes]

Subpart 5—Hedge arrangement disclosure

13.217 to 13.236

[No changes]

Schedules 13.1 to 13.3 and 13.4

[No changes]

Schedule 13.3A cl 13.135B
Calculation of interim prices in scarcity pricing situation

OPTION A – Scaled floor and cap at $10K

1 Calculation of interim prices in island scarcity pricing situation

(1) If an **island scarcity price situation** is declared under clause 13.135A to exist in a **trading period**, the **pricing manager** must calculate **interim prices** and **interim reserve prices** in the relevant **island** for that **trading period** in accordance with the following:

(a) calculate initial **interim prices** and **interim reserve prices** for the relevant **island** for that **trading period** in accordance with clause 13.135:

(b) calculate the **island GWAP** in accordance with subclause (2):

(c) calculate the scarcity pricing factor in accordance with subclause (3):

(d) calculate **interim prices** by multiplying the initial **interim prices** calculated under paragraph (a) by the scarcity pricing factor:

(e) calculate **interim reserve prices** by multiplying the initial **interim reserve prices** calculated under paragraph (a) by the scarcity pricing factor.

(2) The **island GWAP** must be calculated in accordance with the following formula:

$$GWAP_{ISL} = \frac{\sum_{g=1}^{n} (Q_g * P_g)}{\sum_{g=1}^{n} Q_g}$$

where

$GWAP_{ISL}$ is the **island GWAP**

Q_g is the scheduled quantity of generation for **generator** g in the **island**

P_g is the **interim price** at the **node** where **generator** g injects **electricity** in the **island**

(3) The scarcity pricing factor must be calculated in accordance with the following formula:

$$X = \frac{\$10{,}000}{GWAP_{ISL}}$$

where

X is the scarcity pricing factor

$GWAP_{ISL}$ is the **island GWAP**

2 Calculation of interim prices in national scarcity pricing situation

(1) If a **national scarcity price situation** is declared to exist in a **trading period** under clause 13.135A, the **pricing manager** must calculate **interim prices** and **interim reserve prices** for that **trading period** in accordance with the following:

(a) calculate initial **interim prices** and **interim reserve prices** for that **trading period** in accordance with clause 13.135:

(b) calculate the **national GWAP** in accordance with subclause (2):

(c) calculate the scarcity pricing factor in accordance with subclause (3):

(d) calculate **interim prices** by multiplying the initial **interim prices** calculated under paragraph (a) by the scarcity pricing factor:

(e) calculate **interim reserve prices** by multiplying the initial **interim reserve prices** calculated under paragraph (a) by the scarcity pricing factor.

(2) The **national GWAP** must be calculated in accordance with the following formula:

$$GWAP_{NAT} = \frac{\sum_{g=1}^{n} (Q_g * P_g)}{\sum_{g=1}^{n} Q_g}$$

where

$GWAP_{NAT}$ is the **national GWAP**

Q_g is the scheduled quantity of generation for **generator** g in both **islands**

P_g is the **interim price** at the **node** where **generator** g injects **electricity** in both **islands**

(3) The scarcity pricing factor must be calculated in accordance with the following formula:

$$X = \frac{\$10{,}000}{GWAP_{NAT}}$$

where

X is the scarcity pricing factor

$GWAP_{NAT}$ is the **national GWAP**

OPTION B – Flat pricing + floor and cap at $10K

1 Calculation of interim prices in island scarcity pricing situation

(1) If an **island scarcity pricing situation** is declared to exist under clause 13.135A, the **pricing manager** must calculate **interim prices** in the relevant **island** for that **trading period** in accordance with the following:

(a) calculate **interim prices** in the relevant **island** for that **trading period** in accordance with clause 13.135:

(b) calculate the transmission loss adjustment factor in accordance with subclause (2):

(c) set all generation (**injection**) prices to $10,000/**MWh**;

(d) calculate all purchase (**offtake**) prices by multiplying $10,000/**MWh** by the transmission loss adjustment factor.

(2) The transmission loss adjustment factor must be calculated in accordance with the following formula:

$$TLAF_{ISL} = 1 + \frac{\sum_{g=1}^{n} Q_g + Q_{HVDC} - \sum_{L=1}^{n} Q_L}{\sum_{L'=1}^{n} Q_{L'}}$$

where

TLAF	is the transmission loss adjustment factor
Q_g	is the scheduled quantity of generation for **generator** g
Q_{HVDC}	is the scheduled quantity of **electricity** received across the **HVDC link** in the **island**
Q_L	is the scheduled quantity of **electricity** purchased by load L
$Q_{L'}$	is the positive scheduled quantity of **electricity** purchased by load L

2 Calculation of interim prices in national scarcity pricing situation

(1) If a **national scarcity pricing situation** is declared to exist under clause 13.135A, the **pricing manager** must calculate **interim prices** for that **trading period** in accordance with the following:

(a) calculate **interim prices** for that **trading period** in accordance with clause 13.135;

(b) calculate the transmission loss adjustment factor in accordance with subclause (2);

(c) set all generation (**injection**) prices to \$10,000/**MWh**;

(d) calculate all purchase (**offtake**) prices by multiplying \$10,000/**MWh** by the transmission loss adjustment factor.

(2) The transmission loss adjustment factor must be calculated in accordance with the following formula:

$$TLAF_{NAT} = 1 + \frac{\sum_{g=1}^{n} Q_g - \sum_{L=1}^{n} Q_L}{\sum_{L'=1}^{n} Q_{L'}}$$

where

TLAF	is the transmission loss adjustment factor
Q_g	is the scheduled quantity of generation for **generator** g in both **islands**
Q_L	is the scheduled quantity of **electricity** purchased by load L in both **islands**
$Q_{L'}$	is the positive scheduled quantity of **electricity** purchased by load L in both **islands**

3 Calculation of interim reserve prices in scarcity pricing situation

(1) If an **island scarcity price situation** is declared to exist under clause 13.135A, the **pricing manager** must set **interim reserve prices** to half of the generation (**injection**) price set under clause 1(1)(c).

(2) If a **national scarcity price situation** is declared to exist under clause 13.135A, the **pricing manager** must set **interim reserve prices** to half of the generation (**injection**) price set under clause 2(1)(c).

OPTION C – Scaled pricing + floor at $10K and cap at $20K

1 Calculation of interim prices in island scarcity pricing situation

(1) If an **island scarcity price situation** is declared under clause 13.135A to exist in a **trading period**, the **pricing manager** must calculate **interim prices** and **interim reserve prices** in the relevant **island** for that **trading period** in accordance with the following:

(a) calculate initial **interim prices** and **interim reserve prices** for the relevant **island** for that **trading period** in accordance with clause 13.135:

(b) calculate the **island GWAP** in accordance with subclause (2):

(c) calculate the scarcity pricing factor in accordance with subclause (3):

(d) calculate **interim prices** by multiplying the initial **interim prices** calculated under paragraph (a) by the scarcity pricing factor:

(e) calculate **interim reserve prices** by multiplying the initial **interim reserve prices** calculated under paragraph (a) by the scarcity pricing factor.

(2) The **island GWAP** must be calculated in accordance with the following formula:

$$GWAP_{ISL} = \frac{\sum_{g=1}^{n} (Q_g * P_g)}{\sum_{g=1}^{n} Q_g}$$

where

$GWAP_{ISL}$ is the **island GWAP**

Q_g is the scheduled quantity of generation for **generator** g in the **island**

P_g is the **interim price** at the **node** where **generator** g injects **electricity** in the **island**

(3) The scarcity pricing factor is determined as follows:

(a) if the **island GWAP** is greater than or equal to $10,000/**MWh** and less than or equal to $20,000/**MWh**, the scarcity pricing factor is 1

(b) if the **island GWAP** is less than $10,000/**MWh**, the scarcity pricing factor is calculated in accordance with the following formula:

$$X = \frac{\$10{,}000}{GWAP_{ISL}}$$

where

X is the scarcity pricing factor

$GWAP_{ISL}$ is the **island GWAP**

(c) if the **island GWAP** is greater than $20,000/**MWh**, the scarcity pricing factor is calculated in accordance with the following formula:

$$X = \frac{\$20{,}000}{GWAP_{ISL}}$$

where

X is the scarcity pricing factor

$GWAP_{ISL}$ is the **island GWAP**

2 Calculation of interim prices in national scarcity pricing situation

(1) If a **national scarcity price situation** is declared to exist in a **trading period** under clause 13.135A, the **pricing manager** must calculate **interim prices** and **interim reserve prices** for that **trading period** in accordance with the following:

(a) calculate initial **interim prices** and **interim reserve prices** for that **trading period** in accordance with clause 13.135:

(b) calculate the **national GWAP** in accordance with subclause (2):

(c) calculate the scarcity pricing factor in accordance with subclause (3):

(d) calculate **interim prices** by multiplying the initial **interim prices** calculated under paragraph (a) by the scarcity pricing factor:

(e) calculate **interim reserve prices** by multiplying the initial **interim reserve prices** calculated under paragraph (a) by the scarcity pricing factor.

(2) The **national GWAP** must be calculated in accordance with the following formula:

$$GWAP_{NAT} = \frac{\sum_{g=1}^{n} (Q_g * P_g)}{\sum_{g=1}^{n} Q_g}$$

where

$GWAP_{NAT}$ is the **national GWAP**

Q_g is the scheduled quantity of generation for **generator** g in both **islands**

P_g is the **interim price** at the **node** where **generator** g injects **electricity** in both **islands**

(3) The scarcity pricing factor is determined as follows:

(a) if the **national GWAP** is greater than or equal to $10,000/**MWh** and less than or equal to $20,000/**MWh**, the scarcity pricing factor is 1

(b) if the **national GWAP** is less than $10,000/**MWh**, the scarcity pricing factor is calculated in accordance with the following formula:

$$X = \frac{\$10{,}000}{GWAP_{NAT}}$$

where

X is the scarcity pricing factor

$GWAP_{NAT}$ is the **national GWAP**

(c) if the **national GWAP** is greater than $20,000/**MWh**, the scarcity pricing factor is calculated in accordance with the following formula:

$$X = \frac{\$20{,}000}{GWAP_{NAT}}$$

where

X is the scarcity pricing factor

$GWAP_{NAT}$ is the **national GWAP**

OPTION D – Flat pricing + floor at $10K and cap at $20K

1 Calculation of interim prices in island scarcity pricing situation

(1) If an **island scarcity pricing situation** is declared to exist under clause 13.135A, the **pricing manager** must calculate **interim prices** in the relevant **island** for that **trading period** in accordance with the following:

(a) calculate **interim prices** in the relevant **island** for that **trading period** in accordance with clause 13.135:

(b) calculate the **island GWAP** in accordance with subclause (2):

(c) calculate the transmission loss adjustment factor in accordance with subclause (3):

(d) set all generation (**injection**) prices to—

(i) if the **island GWAP** is greater than or equal to $10,000/**MWh** and less than or equal to $20,000/**MWh**, the **island GWAP**; or

(ii) if the **island GWAP** is less than $10,000/**MWh**, $10,000/**MWh**; or

(iii) if the **island GWAP is** greater than $20,000/**MWh**, $20,000/**MWh**:

(e) calculate all purchase (**offtake**) prices by multiplying the price set under paragraph (d) by the transmission loss adjustment factor.

(2) The **island GWAP** must be calculated in accordance with the following formula:

$$GWAP_{ISL} = \frac{\sum_{g=1}^{n} (Q_g * P_g)}{\sum_{g=1}^{n} Q_g}$$

where

$GWAP_{ISL}$	is the **island GWAP**
Q_g	is the scheduled quantity of generation for **generator** g in the **island**
P_g	is the **interim price** at the **node** where **generator** g injects **electricity** in the **island**

(3) The transmission loss adjustment factor must be calculated in accordance with the following formula:

$$TLAF_{ISL} = 1 + \frac{\sum_{g=1}^{n} Q_g + Q_{HVDC} - \sum_{L=1} Q_L}{\sum_{L'=1}^{n} Q_{L'}}$$

where

TLAF	is the transmission loss adjustment factor

Q_g is the scheduled quantity of generation for **generator** g

Q_{HVDC} is the scheduled quantity of **electricity** received across the **HVDC link** in the **island**

Q_L is the scheduled quantity of **electricity** purchased by load L

$Q_{L'}$ is the positive scheduled quantity of **electricity** purchased by load L

2 Calculation of interim prices in national scarcity pricing situation

(1) If a **national scarcity pricing situation** is declared to exist under clause 13.135A, the **pricing manager** must calculate **interim prices** for that **trading period** in accordance with the following:

(a) calculate **interim prices** for that **trading period** in accordance with clause 13.135:

(b) calculate the **national GWAP** in accordance with subclause (2):

(c) calculate the transmission loss adjustment factor in accordance with subclause (3):

(d) set all generation (**injection**) prices to—

(i) if the **national GWAP** is greater than or equal to $10,000/**MWh** and less than or equal to $20,000/**MWh**, the **national GWAP**; or

(ii) if the **national GWAP** is less than $10,000/**MWh,** $10,000/**MWh**; or

(iii) if the **national GWAP is** greater than $20,000/**MWh,** $20,000/**MWh**:

(e) calculate all purchase (**offtake**) prices by multiplying the price set under paragraph (d) by the transmission loss adjustment factor.

(2) The **national GWAP** must be calculated in accordance with the following formula:

$$GWAP_{NAT} = \frac{\sum_{g=1}^{n} (Q_g * P_g)}{\sum_{g=1}^{n} Q_g}$$

where

$GWAP_{NAT}$ is the **national GWAP**

Q_g is the scheduled quantity of generation for **generator** g in both **islands**

P_g is the **interim price** at the **node** where **generator** g injects **electricity** in both **islands**

(3) The transmission loss adjustment factor must be calculated in accordance with the following formula:

$$TLAF_{NAT} = 1 + \frac{\sum_{g=1}^{n} Q_g - \sum_{L=1} Q_L}{\sum_{L'=1}^{n} Q_{L'}}$$

where

TLAF is the transmission loss adjustment factor

Q_g is the scheduled quantity of generation for **generator** g in both **islands**

Q_L is the scheduled quantity of **electricity** purchased by load L in both **islands**

$Q_{L'}$ is the positive scheduled quantity of **electricity** purchased by load L in both **islands**

3 Calculation of interim reserve prices in scarcity pricing situation

(1) If an **island scarcity price situation** is declared to exist under clause 13.135A, the **pricing manager** must set **interim reserve prices** to half of the generation (**injection**) price set under clause 1(1)(d).

(2) If a **national scarcity price situation** is declared to exist under clause 13.135A, the **pricing manager** must set **interim reserve prices** to half of the generation (**injection**) price set under clause 2(1)(d).

Code amendments proposed for stress test regime

Subpart 5A—Risk disclosure

13.236A Disclosing participants must prepare and submit risk disclosure statements

(1) Each **disclosing participant** must prepare a **risk disclosure statement** for each quarter beginning 1 January, 1 April, 1 July, and 1 October in each year.

(2) The **disclosing participant** must submit the **risk disclosure statement** to the **Authority** no later than 5 **working days** before the beginning of the quarter to which the statement relates.

13.236B Authority must publicise a base case and stress test

(1) The **Authority** must **publicise** a notice setting out a **base case** and 1 or more **stress tests** for the purposes of this subpart.

(2) If the **Authority** has not **publicised** a notice under subclause (1) at least 30 **working days** before the start of a quarter, a **disclosing participant** is not required to submit a **risk disclosure statement** for the next quarter.

(3) If the **Authority publicises** an amendment to a notice, or revokes and replaces a notice, within 30 **working days** before the start of a quarter, **disclosing participants** must prepare **risk disclosure statements** for the immediately following quarter in accordance with the notice as in force immediately before the amendment or replacement was made and not in accordance with the notice as amended or replaced.

13.236C Content of risk disclosure statements

(1) A **risk disclosure statement** submitted to the **Authority** must include the following:

(a) for each **stress test event**, the change (as compared with the **base case**) in net cash flow from operating activities that the **disclosing participant** has calculated that it would experience if the circumstances set out in the **stress test** arose in the period specified in the **stress test**:

(b) the **disclosing participant's** annual net cash flow from operating activities as set out in the **disclosing participant's** most recent set of audited annual financial statements:

(c) the **disclosing participant's** level of shareholders' equity as set out in the **disclosing participant's** most recent set of audited annual financial statements:

(d) the **disclosing participant's** forecast of the amount of **electricity** that the **disclosing participant** expects to purchase and sell on the **wholesale market** in the quarter to which the statement relates:

(e) a statement certifying that the **disclosing participant** has provided to each of the **disclosing participant's** customers who, in the quarter to which the **risk disclosure statement** relates, has entered into or renewed a contract with the **disclosing participant** that results in any **electricity** supplied to the customer being determined directly by reference to the **final price** at a **GXP**, information to enable the customer to consider the outcomes of applying the **stress test** or **stress tests** to the customer:

(f) a statement certifying that the board of the **disclosing participant** has considered the **risk disclosure statement**.

(2) In preparing a **risk disclosure statement**, a **disclosing participant** must have regard to all relevant factors, including (without limitation)—

(a) any financial instruments in which the **disclosing participant** has an interest; and

(b) any other measures that the **disclosing participant** has in effect to manage the risk arising from its exposure to the **wholesale market**; and

(c) any other arrangements that the **disclosing participant** has in place to manage that risk; and

(d) any amounts of **electricity** that the **disclosing participant** expects to buy from, or sell to, the **clearing manager**.

13.236D Risk disclosure statement must be signed by directors

(1) Every **risk disclosure statement** must be signed and dated on behalf of the board of the **disclosing participant** submitting the statement by 2 directors of the **disclosing participant** or, if the **disclosing participant** has only 1 director, by that director.

(2) A **risk disclosure statement** must be signed and dated no earlier than 20 **working days** and no later than 5 **working days** before the beginning of the quarter to which the statement relates.

13.236E Authority may require risk disclosure statement to be updated

(1) The **Authority** may, by notice in writing to a **disclosing participant** who submitted a **risk disclosure statement**,

require the **disclosing participant** to update the **risk disclosure statement**.

(2) If a **disclosing participant** receives a request from the **Authority** under subclause (1), the **disclosing participant** must submit an updated **risk disclosure statement** within 10 **working days** after the date on which the **disclosing participant** received the request.

(3) Clauses 13.236C and 13.236D apply to a **risk disclosure statement** updated under this clause.

13.236F Authority may require an independent audit of a risk disclosure statement

(1) The **Authority** may, in its discretion, carry out an **audit** of a **risk disclosure statement**.

(2) If the **Authority** decides under subclause (1) that a **risk disclosure statement** should be subject to an **audit**, the **Authority** must require the relevant **disclosing participant** to nominate an appropriate **auditor**.

(3) The **disclosing participant** must provide that nomination within a reasonable timeframe.

(4) The **Authority** may direct the **disclosing participant** to appoint the **auditor** nominated by the **disclosing participant**.

(5) If the **disclosing participant** fails to nominate an appropriate **auditor** within 5 **working days**, the **Authority** may direct the **disclosing participant** to appoint an **auditor** of the **Authority's** choice.

(6) The **disclosing participant** must appoint an **auditor** in accordance with a direction made under subsection (4) or subsection (5).

(7) A **disclosing participant** subject to an **audit** under this clause must, on request from the **auditor**, provide the **auditor** with such information as the **auditor** reasonably requires in order to **audit** the **risk disclosure statement**.

(8) The **disclosing participant** must provide the information no later than 5 **working days** after receiving a request from the **auditor** for the information.

(9) The **disclosing participant** must ensure that the **auditor** produces an **audit** report on the **risk disclosure statement** and submits the **audit** report to the **Authority**.

(10) Before the **audit** report is submitted to the **Authority**, any failure of the **risk disclosure statement** to comply with this subpart must be referred back to the **disclosing participant** for comment.

(11) The comments of the **disclosing participant** must be included in the **audit** report.

(12) The **disclosing participant** may require that the **auditor** does not provide the **Authority** with a copy of any information that the **disclosing participant** has provided to the **auditor** in accordance with subclause (7).

13.236G Confidentiality of risk disclosure statements

(1) Subject to the Official Information Act 1982, the **Authority** must keep all **risk disclosure statements** submitted to the **Authority** confidential.

(2) Despite subclause (1), the **Authority** may **publicise** information regarding the **risk disclosure statements** in a form that does not associate specific information with any **disclosing participant**.