Scarcity Pricing & Default Buyback Technical Group

Scarcity price issues

12 August 2010

Note: this paper includes quantitative information on a range of issues. The information should be treated as indicative as this point as the underlying data and calculations have not yet been audited.

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Purpose

1. Earlier papers have set out a number of *possible* design elements for a scarcity pricing regime. These include:
   - setting energy prices to a value that represents the value of lost load (VOLLu) for 'un-notified' demand curtailment during grid emergency events;
   - setting energy prices to a value that represents the value of lost load (VOLLn) for 'notified' demand curtailment during rolling outages;
   - setting instantaneous reserves prices to a pre-defined level or levels during periods where there are insufficient instantaneous reserves;
   - applying a floor to energy prices during periods when public conservation campaigns are running;
   - applying a market price cap to energy prices based on the value of VOLLu; and
   - applying a cumulative price threshold (CPT) to energy prices.
2. This paper explores some of these issues in more detail. In particular it sets out the Commission's current thinking on the following:
   - the process for setting a scarcity price value for rolling outages;
   - the merits of a price floor applied for public conservation campaigns;
   - the ability of a single cumulative price threshold mechanism to address both grid emergency and rolling outage situations ; and
   - broad options for implementing scarcity pricing in the market pricing engine.
3. The paper does not reach final views on these issues because further analysis is required on each. However, the Commission welcomes feedback on the analysis undertaken to date, and the priorities for future analytical work.
4. As with earlier materials, the quantitative information included in this paper has not been audited, and should therefore be treated as indicative at this point.

Scarcity value for rolling outages

5. A paper for the last meeting of the Scarcity Pricing and Default Buyback Technical Group (the Group) described two methods for determining scarcity price values for

capacity shortages[1], i.e. values to apply in demand curtailment events where electricity users suffer forced outages with little or no warning. The paper also included a range of indicative values based on the application of one of the approaches[2].

6. The paper noted that separate consideration should be given to determining a distinct scarcity price value to apply in rolling outages. These are demand curtailment instructions that can be triggered as a last resort to avoid untargeted demand shedding. The key features of the current arrangements for rolling outages are[3]:

   (a) before implementing this measure, the Commission would declare the intention to trigger rolling outages;

   (b) the Commission would consult with the System Operator about the need for rolling outages. If they are assessed as necessary, it would also consult on the depth of the cut that should occur (which can be up to 25%);

   (c) the System Operator would liaise with electricity distributors and direct-connect users to implement rolling outages;

   (d) rolling outages could be required to address a sudden event (e.g. loss of a major infrastructure item) or a developing situation (e.g. a prolonged and severe drought);

   (e) rolling outages would be implemented by:

      (i) electricity distributors cutting feeders that supply lower priority loads for defined periods (typically hours); and

      (ii) direct connect users shedding load at their sites.

7. The reasons that a separate value might be justified for rolling outages are that:

   - the duration and timing of curtailment would be managed, to the extent feasible, to minimise the resulting costs to society. For example, it is expected that cuts to residential and commercial feeders would generally avoid the hours of darkness to minimise risks to health and safety;
   - cuts would be targeted, to the extent feasible, across distribution feeders and grid exit points in a manner designed to reflect the assessed priority of interruption to different customer groups. For example, it is expected that distribution feeders

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1 See *Framework for setting scarcity price values during capacity shortfalls,* Electricity Commission, July 2010

2 From around $5,500/MWh to $38,500/MWh. This includes the current value used for transmission planning purposes. The upper and lower values were based on assumptions which appear to be relatively implausible, but were nonetheless included for comparative purposes.

3 Some aspects of these arrangements will modified assuming the Electricity Industry Bill is enacted. However, the underlying features are unlikely to change materially.

serving major hospitals and air traffic control centres would be in the last categories to be curtailed; and

- cuts would be signalled in advance. This should allow electricity users with the most critical needs (and therefore with the highest curtailment costs) to take mitigating actions. For example, this should allow alternative arrangements to be put in place for residential customers that are reliant on power supply for medical devices and commercial users may be able to schedule processes to reduce disruption.

8. The following sections describe approaches that could be used to establish a scarcity value to apply for rolling outages[4].

Scarcity value for rolling outages – referential approach

9. The simplest approach would be to determine the scarcity value for rolling outages by reference to the scarcity value for un-notified grid emergency curtailments[5].

10. The current trigger condition implies that rolling outages would be implemented when the system is at the 50% risk curve. This in turn could suggest the scarcity price for rolling outages would be 50% of the scarcity price for capacity curtailments[6], assuming that the purpose of rolling outages is to avoid more costly untargeted curtailments.

11. While there is some logic for the approach, to use it in the derivation of a scarcity value implies reliance on an underlying assumption that the 50% trigger level reflects a full economic assessment of relative costs of rolling outages versus the cost of capacity curtailments. In reality, neither the cost of targeted or untargeted outages is easily represented by a single $/MWh number.

12. Costs of both types of outage will be affected by the timing, coverage and duration of the outages that would occur. Costs would be expected to be lower for cuts that are more limited in their coverage, and which could therefore be targeted at less critical categories of users. However, costs would be higher for wider outages.

13. These factors suggest that while the referential yardstick may provide some guidance, it is also useful to explore other approaches to assessing the likely costs of rolling outages.

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[4] It is expected that scarcity prices for rolling outages would be applied for the whole area experiencing scarcity (subject to any minimum geographic trigger), not just the particular nodes where curtailment is occurring in any specific trading period.

[5] This paper uses the terms un-notified curtailment, capacity-based curtailment and grid emergency curtailment to refer to an event where forced demand shedding occurs with little or notice – i.e. instructed load shedding that occurs other than during rolling outages as defined in the Electricity Governance (Security of Supply) Regulations 2008.

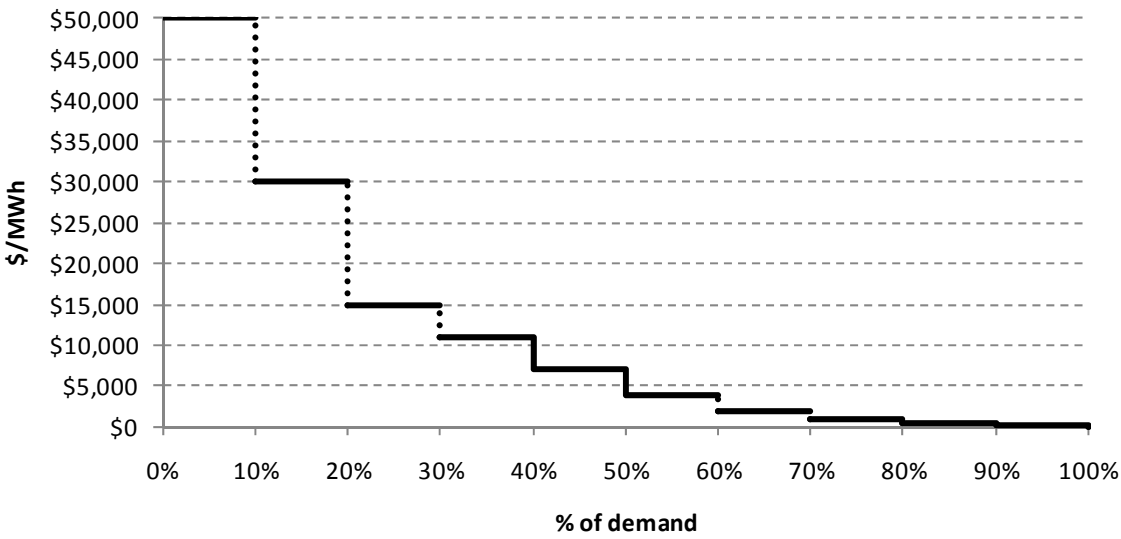
[6] Assuming “more likely than not” is interpreted as when the risk of subsequent outages under Grid Emergency provisions reaches the 50% threshold.

Question 1: What is your view of setting the scarcity price for rolling outages as a proportion of the scarcity price for grid emergency demand curtailment?

Scarcity value for rolling outages – first principles

14. One way to examine the likely cost of rolling outages is to consider the issue from first principles. Figure 1 shows a notional demand curve for electricity at a point in time.

Figure 1: Illustrative demand curve for electricity and curtailment cost



15. An untargeted cut would be likely to result in costs that are approximately equal to the weighted average value of demand in the half hour. In this illustrative example, it would equate to around $12,000/MWh. By contrast, a targeted curtailment should be able to focus on segments of less critical demand – with values well below $12,000/MWh. This chart illustrates that two critical issues are:
    - the depth of the cut that is required; and
    - the extent to which costs vary across the demand curve.
16. The following sections seek to shed light on these issues.

Shape of demand curve – network company participant outage plans

17. Some information is available on the shape of the demand curve for electricity. One source is the data provided by network companies and direct connect users in their 'Participant Outage Plans'. Specified users must furnish these plans pursuant to the Electricity Governance (Security of Supply) Regulations 2008.

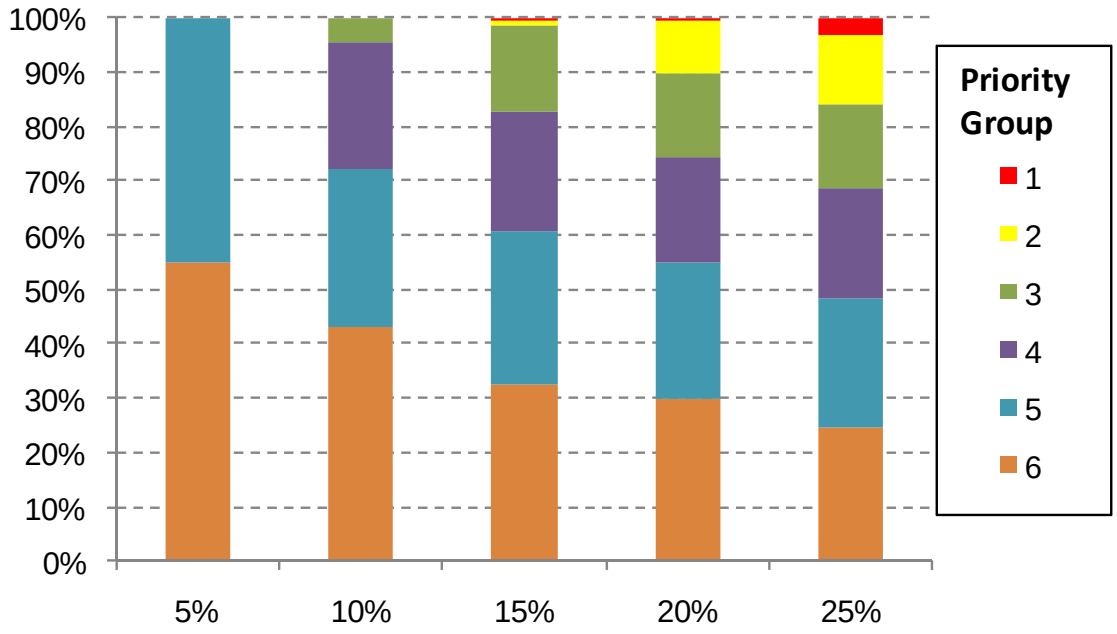
18. The information in the network company plans sets out how they would expect to achieve differing levels of savings. In particular, the plans set out the extent to which different categories of demand would be affected by differing levels of demand curtailment. The broad priority groups are set out in Table 1.

Table 1: Broad priority categories for rolling outages

Priority	Priority Concern	Maintain Supply to:
1	Public health and safety	Major hospitals, air traffic control centres, and emergency operation centres.
2	Important public services	Energy control centres, communication networks, water and sewage pumping, fuel delivery systems, major ports, public passenger transport and major supermarkets.
3	Public health and safety	Minor hospitals, medical centres, schools, and street lighting.
4	Animal health and food production/storage	Dairy farms, milk production facilities, chicken sheds and cool stores.
5	Domestic production	Commercial and industrial premises.
6	Disruption to consumers	Residential premises.

19. The information from approved South Island network company plans has been collated to identify the likely mix of priority groups to achieve differing levels of savings. This information is shown in Figure 2 in the form a bar for each level of saving (5% to 25%). It is important to note that where AUFLS requirements are maintained by feeders in lower priority groups, rolling cuts may affect higher priority groups than illustrated, and therefore incur higher costs.

Figure 2: Expected mix of priority groups for differing savings



20. The chart indicates that the extent to which different priority groups would be affected by rolling outages will be strongly influenced by the required aggregate level of savings. If savings of 10% or less are required, it appears that outages would largely be limited to Priority Groups 5 and 6. As the level of required savings rises, the coverage of affected Priority Groups would increase.

21. It is likely that the average cost of curtailment for each group will differ. For example, a study of the value of reliability for different customer groups in Victoria concluded that for transmission planning purposes, the value of reliability to residential users was approximately 25% of the average value across all customer groups[7]. While no equivalent data is currently available in New Zealand, a broadly similar relationship might be expected to apply. This would tend to support the view that rolling cuts are likely to incur a lower cost than untargeted demand curtailment, especially for lower levels of required savings.

Shape of demand curve – direct connect participant outage plans

22. Direct connect users are also required to furnish participant outage plans. The plans for these users can take one of two forms:

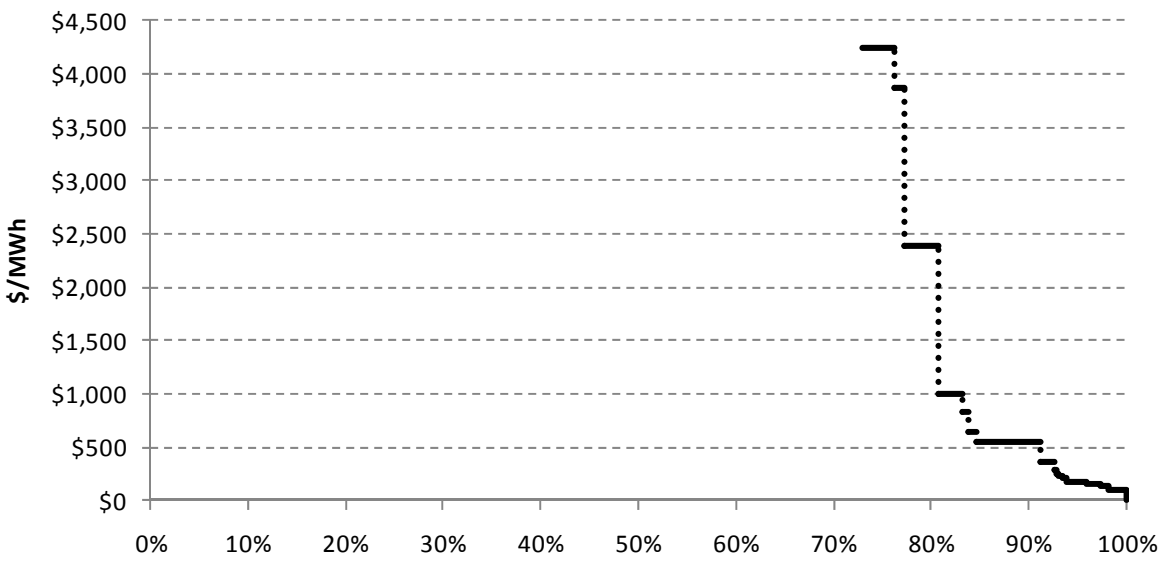
[7] The value of customer reliability (VCR) was estimated for different customer groups in Victoria in 2007. In current Australian dollars, the estimates are $55,000/MWh as the weighted average, residential ($13 250/MWh), agricultural ($111 060/MWh), commercial ($90 760/MWh) and industrial ($36 070/MWh), with the weights reflecting the state wide average energy consumption of the different sectors. See Review of the Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events, *AEMC*, May 2010.

- Full information plans: Among other matters, this type of plan must contain information on the expected costs associated with different levels of savings; or
- Partial information plans: these plans are less comprehensive, and may exclude information on expected costs.

23. Specified direct-connect users have an incentive to submit a full information plan because where the Commission seeks to achieve a relatively low savings target (e.g. 5%), it is possible that this could be achieved by cutting supply to lower priority customers within distribution networks. This could mean that direct-connect users might not be required to make additional savings in that event.

24. The cost data contained within full information plans has been aggregated to produce an estimate of a portion of the demand schedule[8]. This information is shown in Figure 3.

Figure 3: Disclosed cost of achieving demand savings for direct connect consumers under Participant Outage Plan



25. The chart suggests that there is a significant variation in costs for differing demand cuts. If larger cuts were required, this would presumably result in even higher levels of cost (assuming users prioritise their load shedding options).

26. Another indicator of curtailment cost is data from winter 2008. As supply conditions deteriorated in that winter, discussions took place between electricity suppliers and some large industrial users about the potential for contracted additional demand curtailment. This information was later provided to the Electricity Commission.

[8] To preserve confidentiality, the chart does not include the results from all plans, and it is expressed as percentages of total demand for the relevant parties. This data reflects both approved and unapproved plans.

27. That information has not been presented in detailed form in this paper to preserve confidentiality. However, it suggested a significant degree of variability in the expected cost of curtailment.

28. The two sources of information on industrial demand both suggest that there would be a reasonable degree of slope on the demand curve, with costs rising as the depth of a curtailment increases.

Question 2: What is your view on how the cost of curtailment will be affected by the depth/coverage of a rolling outage, and how might these costs be defined further?

Depth of rolling outages that might be required

29. As noted earlier, the depth of any curtailment is likely to have a major bearing on the expected cost of forced load shedding. In the case of rolling outages required to address a sudden event (e.g. catastrophic failure of major infrastructure), it is not possible to estimate the depth of the cut because it would depend on the event.

30. The other main scenario is that rolling outages are initiated to address an extreme drought. The potential depth of cut required to address this scenario can be estimated using historic information on hydro inflow variability.

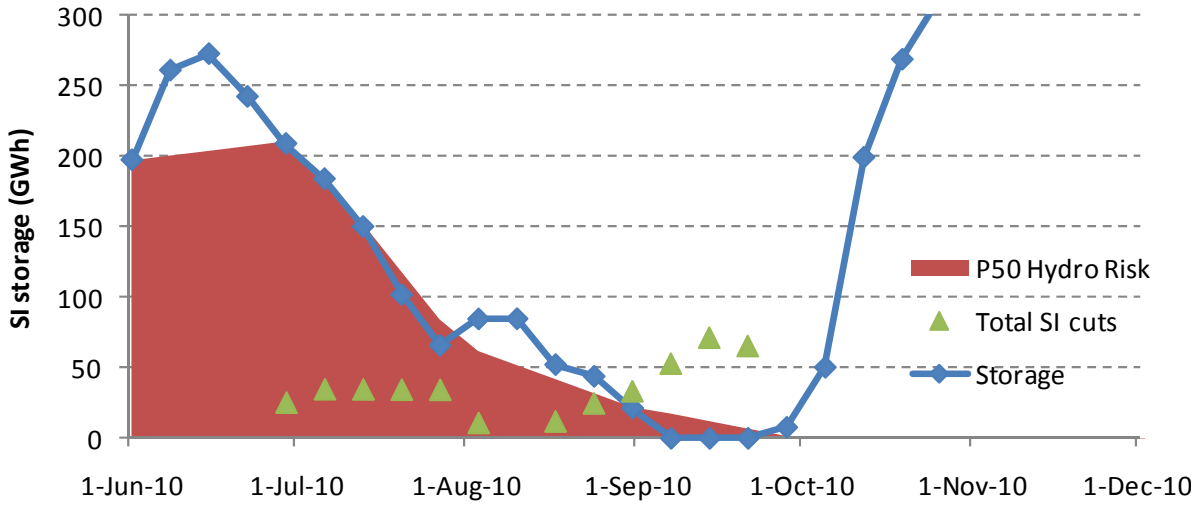
31. An indicative analysis has been carried out for the South Island based on the following assumptions:

    - underlying demand, generation and transmission capacity as at 2010;
    - existing demand savings of 7% due to price-based response and public conservation campaigns; and
    - a decision rule that rolling outages are initiated when storage reaches the 50% risk curve, and that cuts are made to seek to keep the system at the 50% risk curve[9].

32. The application of the decision rule is illustrated by Figure 5. For a given historical sequence, it shows how the depth of the cut is determined by the amount of energy conservation required to hold the system at the 50% risk curve. Because the volume of hydro inflow varies from week to week (even for a single historical sequence), the amount of rolling outage can also vary in this example.

[9] More specifically, cuts of up 10% are applied when the 50% risk curve is reached. If storage reaches zero, 'controlled' cuts are made to avoid 'untargeted' cuts. These are fairly simple decision rules, and more complex rules could be modelled to test the sensitivity of these assumptions.

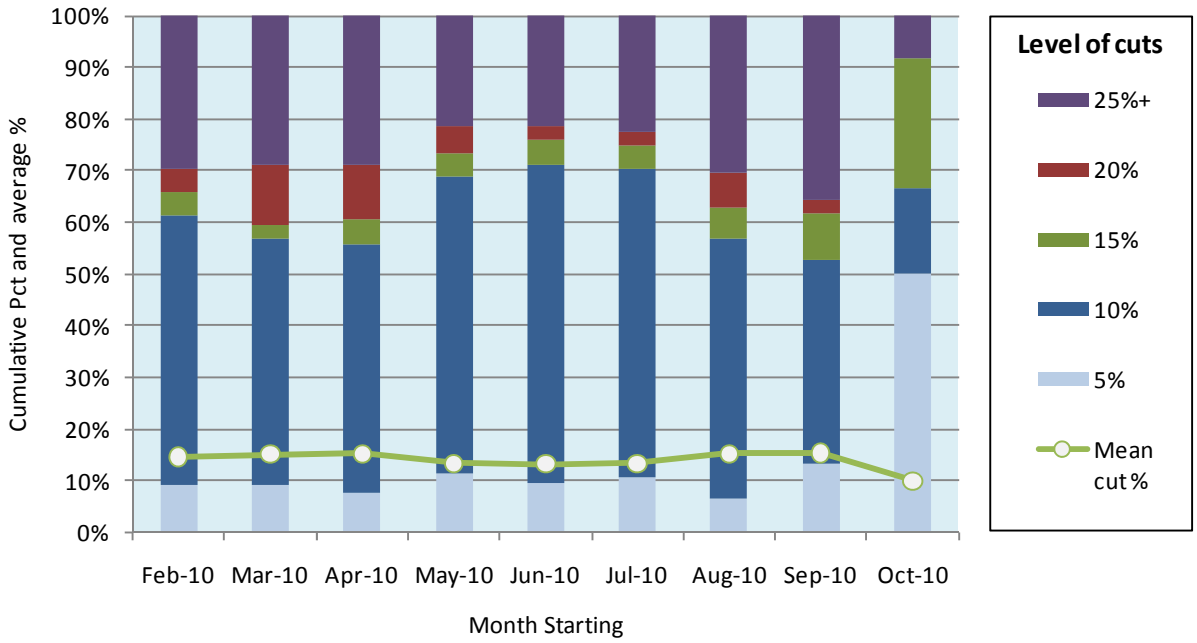
Figure 4: Derivation of depth of rolling cut



33. Repeated simulations of this sort were performed based on historic inflow data and assuming storage had already reached the 50% risk curve. This needs to be kept in mind when considering the following charts. The 50% risk curve corresponds to a storage level where half of the historic sequences would exhaust all available storage (in the absence of any other additional measures to reduce demand).

34. Depending on the assumptions, the 50% risk curve corresponds to a storage level of 200-400GWh in winter, or around 10% of South Island storage capability. As points of comparison, South Island winter demand is around 300GWh per week, and the 1% risk curve in winter 2010 is around 1,200GWh.

Figure 5: Estimated depth of rolling cuts (for storage at P50 hydro risk curve)

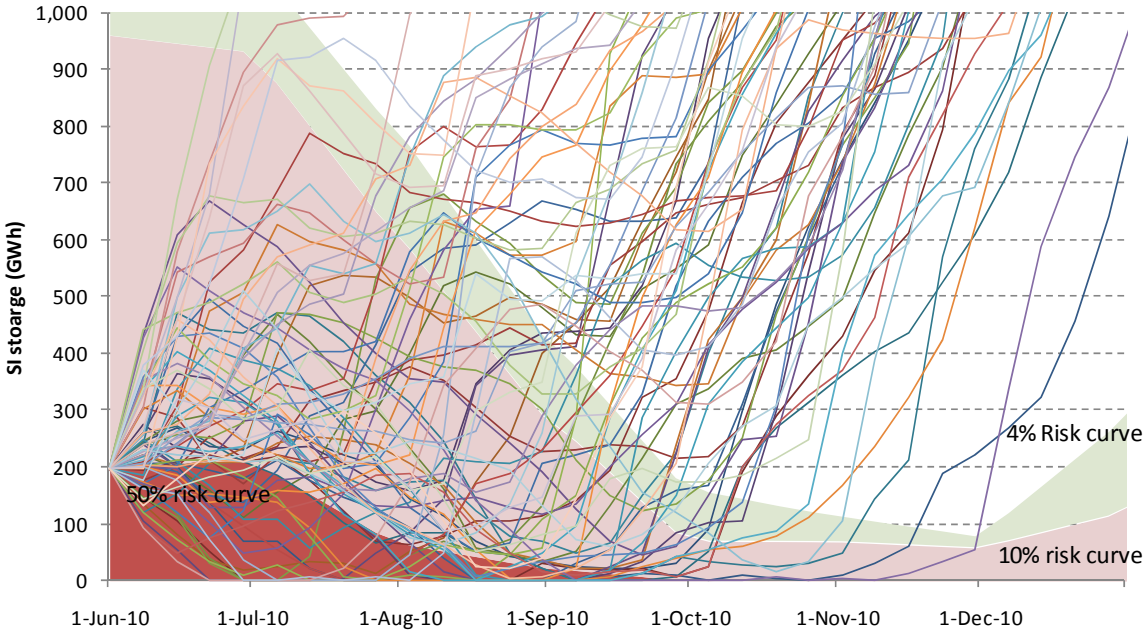


35. The results of the analysis are shown in Figure 5. Note that the depth of cut shown in the chart is the *additional* demand curtailment beyond the savings assumed to be occurring due to price response and public conservation measures. Because the chart shows *additional* demand reductions, the figures are not directly comparable with the figures in Participant Outage Plans (which reference 'normal' demand). Another point to note is that Participant Outage Plans generally use the demand figure from the prior year as the base line[10].

36. The analysis suggests that the expected depth of any curtailment would be sensitive to the time when they are first required, and that in most cases the cuts would be 10% or less. It is also important to emphasise that in many cases, even though the system starts at the 50% risk curve, it swiftly moves into an improved risk position due to inflows (based on historical hydro sequences) without the need for any cuts. This is shown by Figure 6. Accordingly, the 'average' cut shown in the chart is arguably overstated.

[10] Further consideration is being given to whether the various measures of demand reduction can be translated to a common basis for comparison.

Figure 6: Hydro storage trajectories (from P50 hydro risk curve)



37. A further important point to note is that the chart shows the position for the South Island, given the existing North-South transmission constraints. Looking ahead, these constraints are expected to lessen with planned transmission investment. This would make the overall New Zealand position a more relevant point of comparison. If the chart were re-analysed for New Zealand, it would be expected to show lower levels of required curtailment, because hydro inflow variability is a lower ratio of aggregate national demand.

38. This analysis suggests that the volume of curtailment required in many rolling outage scenarios may be sufficiently modest to allow a degree of targeting. Assuming that the targeting can differentiate (roughly) on the basis of demand curtailment cost for different customer categories, this suggests that rolling cuts should be able to achieve power savings at a lower cost than for a grid emergency-type curtailment.

39. This view is further reinforced by the fact that rolling outages would be initiated with prior notice and targeted at times of the day that are expected to produce the least disruption. Neither of these factors is factored into the analysis above.

Question 3: To what extent do you agree that rolling outages are likely to incur less cost to electricity users than cuts initiated under grid emergency arrangements?

Impact on voluntary demand side response and generation incentives

40. Another consideration in setting a scarcity value for rolling outages is the desire to minimise the adverse impact on incentives for generators and demand-side participants to undertake voluntary price-based response. This covers both short term and longer term incentives (i.e. short run marginal costs and long run marginal cost of provision).

41. The paper for the last meeting focussed on the scarcity price value for capacity shortages. It noted that a last resort provider of capacity is also likely to earn some revenue during energy shortages (i.e. rolling outages). The analysis in that paper suggested that around 20-25% of a last resort provider's expected revenue would be attributable to energy constraint periods (based on the existing plant mix, and expected demand profile). An underlying assumption in that analysis was that spot prices in energy constraint situations would rise to around $4,000/MWh. If the rolling outage scarcity value were materially lower than this, it could affect the expected economics for a last resort provider, with a possible impact on the scarcity price value for capacity shortages.

42. In the case of short run incentives, higher cost generators (e.g. diesel-fired plant) are likely to require $400-500/MWh or more to cover their avoidable costs. The costs for demand response are likely to be somewhat higher. This view is based in part on the information discussed above regarding industrial demand, but also the experience in winter 2008. For example[11], in discussing spot prices in 2008 (which peaked at around $400/MWh in weekly average terms), some participants made comments such as:

    - "better to let prices go to $500-$1,000/MWh" – a major user commenting on its view of the price required for demand savings to become economic; and
    - "people want proper amounts of money (~$800/MWh) for demand response" – a stakeholder.

43. Given that voluntary price-induced demand response would be expected to start well before rolling cuts are imposed[12], this would indicate that a scarcity price for rolling outages should be at least $1,000/MWh, if not higher.

Scarcity value for rolling outages - summary

44. There are strong grounds to expect that the cost of demand curtailment under rolling outages would be lower than for un-notified curtailment events. The magnitude of the difference is a matter of judgement, especially as representing each cost with a single figure will involve approximations.

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[11] See www.electricitycommission.govt.nz/pdfs/opdev/secsupply/pdfsconsultation/Winter-Review-Report.pdf

[12] Unless the trigger event was very sudden.

45. Factors that appear relevant in establishing the scarcity value for rolling outages are:
    - it should be materially lower than the scarcity value for un-notified curtailment, given that:
        - evidence suggests there is significant potential to target lower cost curtailment options if rolling outages are applied;
        - the likely depth of cuts that could be required appears to be moderate under many scenarios; and
        - users would have prior notice of any cuts;
    - it should be at least $1,000/MWh to avoid adverse effects on price-based response from generation and demand-side sources.
46. Taken together these factors suggest a value of at least $1,000/MWh, and appreciably lower than the (as yet undefined) scarcity value for (un-notified) curtailment occurring under grid emergency arrangements. This is clearly a wide band, and further work will be undertaken to narrow this range.
47. Another issue to consider is whether there is merit in adopting more than one scarcity price value for rolling outages. For example, different values might be applied depending on the magnitude of the savings being targeted.
48. Additional work is expected to include:
    - further analysis of the depth/duration of different rolling outage scenarios, and linking this to information on categories of demand that would be affected;
    - further review of overseas information on the expected costs for targeted and untargeted load curtailment; and
    - consideration of the forthcoming information from the UMR Research survey on the costs of curtailment for different categories of electricity users.

Question 4: What further analysis could be used to determine the scarcity price(s) to apply during rolling outages?

Price floor during public conservation campaigns

49. The section discusses the relative merits of applying a floor on energy prices during a public conservation campaign,
50. The preceding discussion focussed on applying scarcity prices where forced load shedding is taking place, given that normal market clearing algorithms are likely to yield suppressed spot price signals in these situations. Such situations are also the key focus of scarcity pricing in overseas markets.

As noted in an earlier paper, a separate concern arises in New Zealand about whether spot price signals might be suppressed in the lead up to a energy shortage situation (e.g. a dry year). The concern arises because some participants may seek to suppress short term spot prices by running down scarce hydro storage or thermal fuel stockpiles to protect an existing contract position, even though this increases the risk of subsequent shortage. There is also an increased incentive to call for public conservation campaigns.

51. Such campaigns are widely perceived as demonstrating that the competitive market does not deliver security of supply. Parties with net purchase positions have an incentive to talk up the risks of blackouts and brownouts (even though the actual level of risk is relatively low) to encourage people to reduce consumption. This can exacerbate the sense of crisis and the perception that the electricity market is flawed.

52. To address these concerns, the Ministerial Review proposed a number of measures, including consideration of putting "a floor on spot prices during a conservation campaign or dry year power cuts"[13] – i.e. during periods of tight supply. This mechanism would reduce the benefit that a participant might obtain from 'prematurely' running down hydro storage or fuel reserves, or calling for public conservation measures.

53. Examination of the fuel management issue from first principles lends weight to the concern. A sizeable market participant could have the incentive and means to suppress prices during a tight supply period, depending on its contract position. Application of a floor price could mitigate this concern.

54. However, the incentive to prematurely use fuel only arises if participants believe they will not face the costs of any subsequent shortage, since their contract exposure at that point would be increased. Under current arrangements, this is a real possibility and market participants might not face the true costs of shortage, since spot prices may not reflect scarcity values[14].

55. The proposed introduction of scarcity prices for demand curtailment due to rolling outages could address this issue. Market participants may be less likely to prematurely rundown their reservoirs/thermal stockpiles because the consequences *to them* of subsequent actual shortages will be clearer. For example, if a participant was a net purchaser (because it had run down its fuel resources) during a period when scarcity prices apply, it would face a substantial cost for its spot market purchases.

56. However, it might also be argued that introducing scarcity pricing in the event of rolling outages, but not in the event of conservation campaigns, could increase the incentive on participants to lobby for conservation campaigns. On this view, industry

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[13] From *Summary of Decisions*, *Ministerial Review,* Ministry of Economic Development, 2009.

[14] See paragraphs 7-9 of *Scarcity Pricing – Review of Past Events,* May 2010, for the underlying reasons.

participants would have two sets of incentives to call for and activate conservation campaigns: that is, to get early relief from high spot prices and to reduce the risk that rolling outages, which will trigger scarcity prices, will be required.

57. As noted above, the other related concern with current arrangements is that participants have an incentive to over use public conservation campaigns as a mechanism for managing their financial risks, since this tool operates to reduce a retailer's net spot purchases (the volume effect), and would be expected to reduce spot prices for any remaining unhedged spot exposure (the price effect). The volume effect only affects retailers whose customers reduce consumption during a conservation campaign. The price effect benefits any parties that are net purchasers.

58. To address the concern about over-reliance on public conservation campaigns, consideration is being given to the introduction of a default buyback arrangement (also recommended in the Ministerial Review), where retailers would be required to make a payment to customers which is intended to reflect the value of power savings[15]. This mechanism is designed to remove the incentive on retailers to treat the volume reduction from public conservation measures as a low cost (to them) form of hedging instrument. However, the default buyback mechanism itself would not remove the incentive on parties that are net purchasers to call for public conservation measures as a way to put downward pressure on spot prices.

59. Another consideration is the extent to which any generator offer behaviour intended to suppress spot prices would be apparent to other parties. Increased monitoring and recent changes to bid and offer disclosure arrangements should mean that any unusual behaviour is more easily identified. This may reduce the incentive to undertake such action, given that it is more likely to elicit a countervailing response from other market participants, and/or scrutiny by regulatory authorities.

60. The potential adverse effects of a price floor during public conservation campaigns also need to be considered. The most obvious risk is that the floor is set too high relative to its 'correct' level. This would be expected to lead to unnecessarily high volumes of thermal fuel burn, hydro spill and demand savings, relative to the optimal level. The extent of any such effects cannot be easily quantified, but would depend on the magnitude of any price misalignment. There is also a possibility that participants with a net seller position might alter their behaviour in a way to increase the likelihood of triggering the floor price (e.g. by utilising hydro storage more swiftly).

61. A more subtle risk is that the price floor could become a de facto price cap. This could arise if participants perceive the floor price as the regulator's guidance on prices. If spot prices rose above this level during a conservation campaign, this

[15] However, it should be noted that setting a single buyback value to cover all situations is inherently difficult. In particular, a value to reflect the situation of public conservation campaigns will understate the value to retailers of demand curtailment in rolling outages.

could prompt calls for regulatory action. This type of response has been observed in the past in relation to the Whirinaki offer price.

62. Fear of regulatory action could in turn influence participants' pricing decisions and tend to anchor the spot price around the floor level, irrespective of actual supply conditions. This could be damaging to incentives, as a floor price (by nature) is unlikely to be set at a level which reflects the 'average' set of conditions during public conservation campaigns.

63. In summary, there are a range of qualitative considerations for and against the introduction of a floor price during public conservation campaigns. The overall position depends on the:

- the extent to which the interaction between scarcity pricing for outages, the buyback mechanism, and the price floor will address the underlying concerns; and
- the assessment of the relative incremental benefits and risks of a price floor applied during public conservation campaigns.

64. The Commission intends to undertake quantitative analysis to assess these issues in more detail, In particular, it will seek to:

- assess the likely impact on participants' incentives to call for public conservation campaigns /manage fuel risks if default buybacks, scarcity pricing for rolling outages and a price floor are introduced; and
- the possible effects on dispatch patterns of a floor price.

Question 5: What is are the key factors that determine whether a price floor during public conservation campaigns will be beneficial, and what analysis can be undertaken to assess these factors?

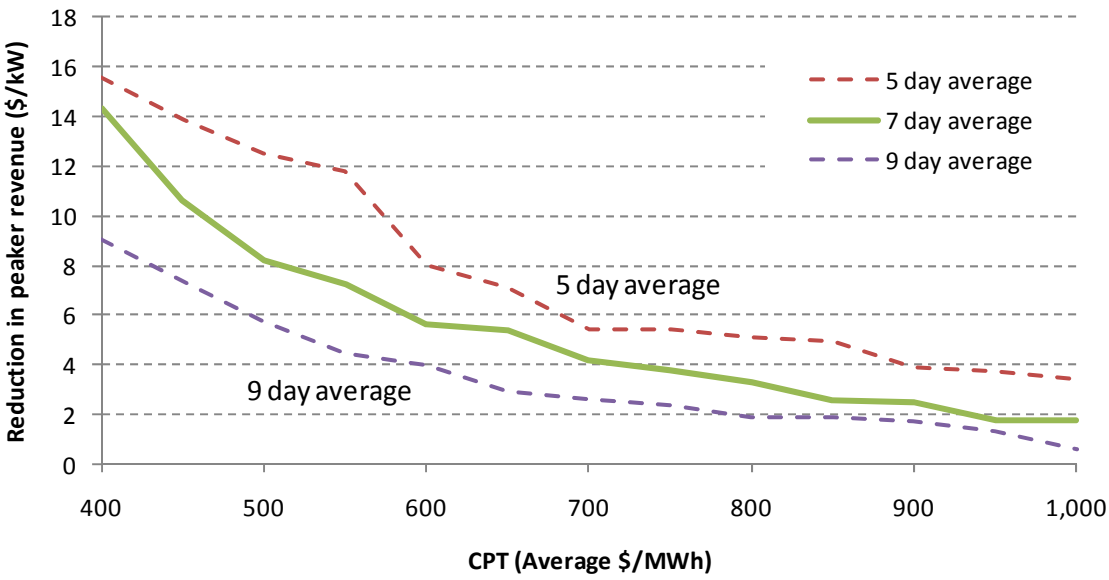
Cumulative Price Threshold(s)

65. At the last meeting, the Group considered a cumulative price threshold (CPT) mechanism as a tool to moderate the potential for extreme price risk. The background paper for the discussion noted that mechanisms of this kind have been applied in other markets with scarcity pricing (e.g. the Australian National Electricity Market).

66. It also noted that with these mechanisms, a balance is required between not unduly reducing the incentives for resource provision, while seeking to moderate the potential for extreme price risk for participants.

67. The paper used the Australian mechanism[16] as its starting point and considered the respective effects on risk and incentives of different CPT settings. For ease of reference, some of the charts from the previous paper are reproduced below. Figure 7 shows the effect on the revenue for a last resort capacity provider of setting the price threshold at varying levels. At $600/MWh, a CPT would reduce expected revenue for a last resort provider by around 5%. As the threshold is raised, the adverse impact on revenue declines.

Figure 7: Effect on capacity provider revenue of differing CPT settings

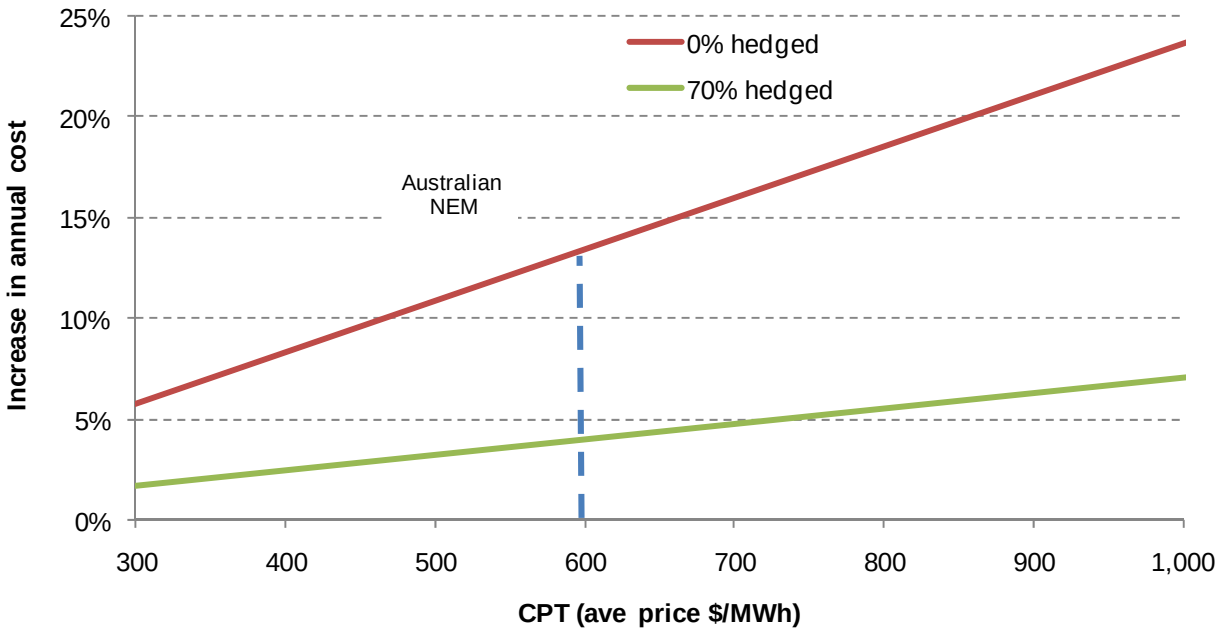


68. The impact of different CPT settings on purchaser risk was considered by looking at the effect on a wholesale buyer's annual purchase cost, assuming the participant is completely unhedged[17] and that the CPT is triggered. This shown in Figure 8.

[16] This is a cumulative price threshold (CPT) of A$187,500 assessed over a 7 day measurement period (triggered if average spot prices over the period exceed A$558/MWh).

[17] The other assumptions are that the buyer has base load demand and has an average purchase price of $75/MWh at other times.

Figure 8: Effect of CPT event on annual procurement cost if unhedged



69. The paper reached a tentative view that a CPT mechanism along the lines of that used in Australia could be workable for capacity shortage events, but that a higher threshold value should be applied, of around $1,000/MWh in average price terms over a 7 day period.

70. The paper also noted that the preceding analysis was intended to address situations of *capacity* constraint. By nature, these are not expected to have a long duration because they are typically due to a plant failure or extreme short term demand spike.

71. The paper noted that a different matrix of CPT settings might be required in a situation where rolling outages are being applied on an extended basis to address an *energy constraint* (i.e. 'dry year').

72. The Group noted this view, but expressed a preference for a single matrix of CPT settings if possible. This section explores whether a single matrix approach is likely to be viable.

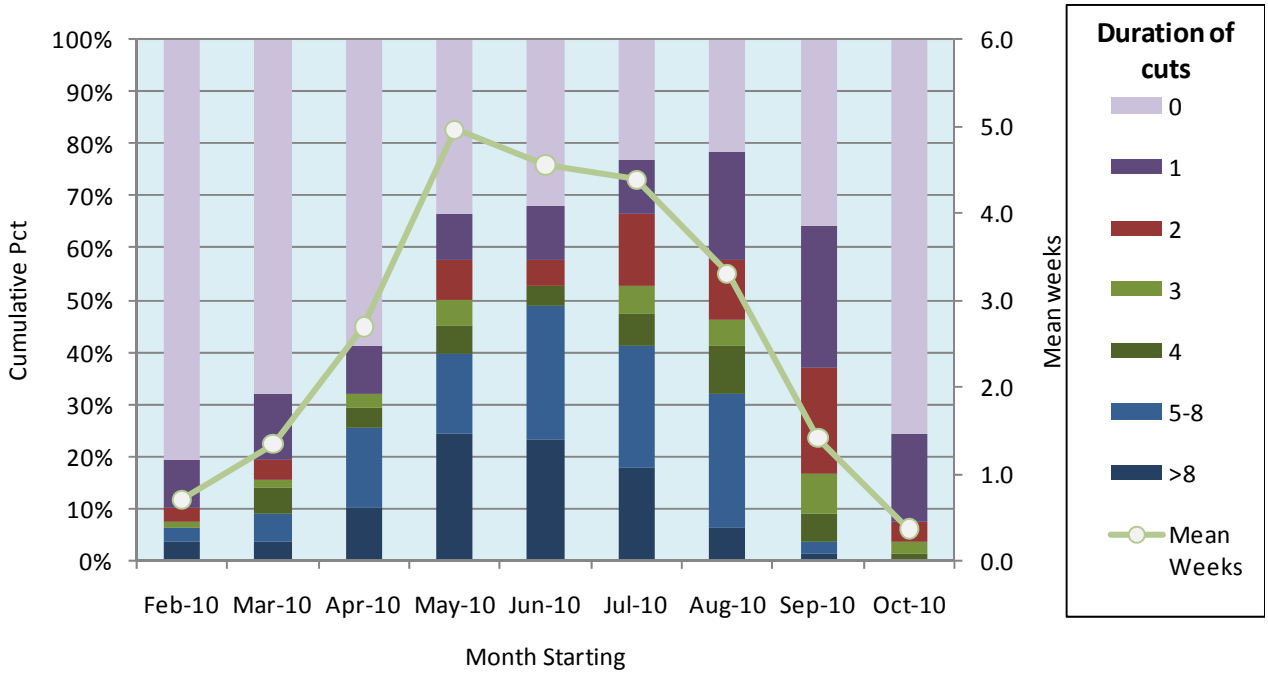
73. The starting point for this additional analysis is to consider the likely duration of a rolling outage 'event' if triggered by an extended drought. This has been considered using the same framework and assumptions as applied earlier in this paper to explore the depth of rolling outages.

74. As with the analysis of the depth of cuts, the nature of the decision 'rules' for triggering and applying outages is important. The analysis assumes cuts are instituted at the point where it is assessed that there is a 50% likelihood that grid emergency curtailment would otherwise be required. Altering this rule would affect the likely durations and depths of rolling outages.

75. The results of the analysis, based on historical inflow patterns and current plant and transmission capacity, are shown in Figure 9. The stack bars show the relative

frequency of cuts of differing durations (left hand axis) and the line shows the mean number of weeks of cuts that would be required (right hand axis).

Figure 9: Expected durations of rolling outages during extended drought



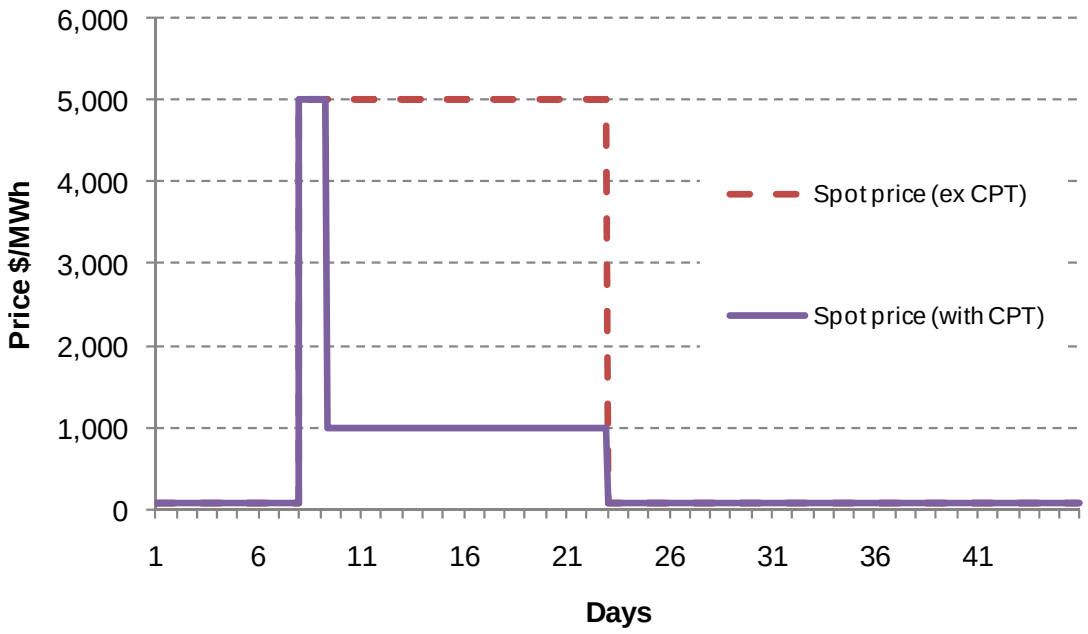
76. The key points are that in a dry sequence:

- the duration of rolling outages can vary widely from one week to over eight weeks, depending on the nature of the event. However, some very extreme events could be longer than eight weeks;
- the expected durations vary according to the time of the year; and
- the mean expected duration of all cuts is approximately four weeks for the May to August timeframe – which is generally regarded as the most critical period. Note that the weeks may not necessarily be contiguous.

77. The analysis indicates that if rolling outages are instituted, there is a high likelihood that they would operate for a number of weeks (but not necessarily contiguous weeks).

78. This means that if a CPT designed to address short term capacity shortages were applied, it would be likely to be triggered and therefore have an impact on final spot prices. Figure 10 shows the effect on spot prices if the scarcity price for rolling outages was set at $5,000/MWh (as an indicative value), and a 7 day CPT set at $1,000 MWh was applied. The example assumes that rolling outages are applied for two weeks. This period is shorter than the mean expectation for rolling outages (around 4 weeks if started in May – August), but recognises that rolling outages may not be applied on a continuous basis.

Figure 10: Effect of CPT set at $1,000/MWh (2 week event)



79. The impact of the conventional 7 day CPT is expected to be quite marked because it will 'bite' early in the event. In this example, it reduces the gross spot revenue/cost by 71%. An important point to note is that no 'ramp up' or 'ramp down' is assumed for spot prices. In an energy shortage, a more gradual price transition would be expected. If this effect was taken into account, the expected impact on spot prices (in terms of % change) is expected to be larger.

80. While the spot price reduction would reduce costs for purchasers, it would also materially affect incentives for provision of voluntary demand response and generation. In effect, a CPT set in this form would alter the scarcity value for rolling outages, since it is almost certain to be triggered fairly early in many rolling outage events.

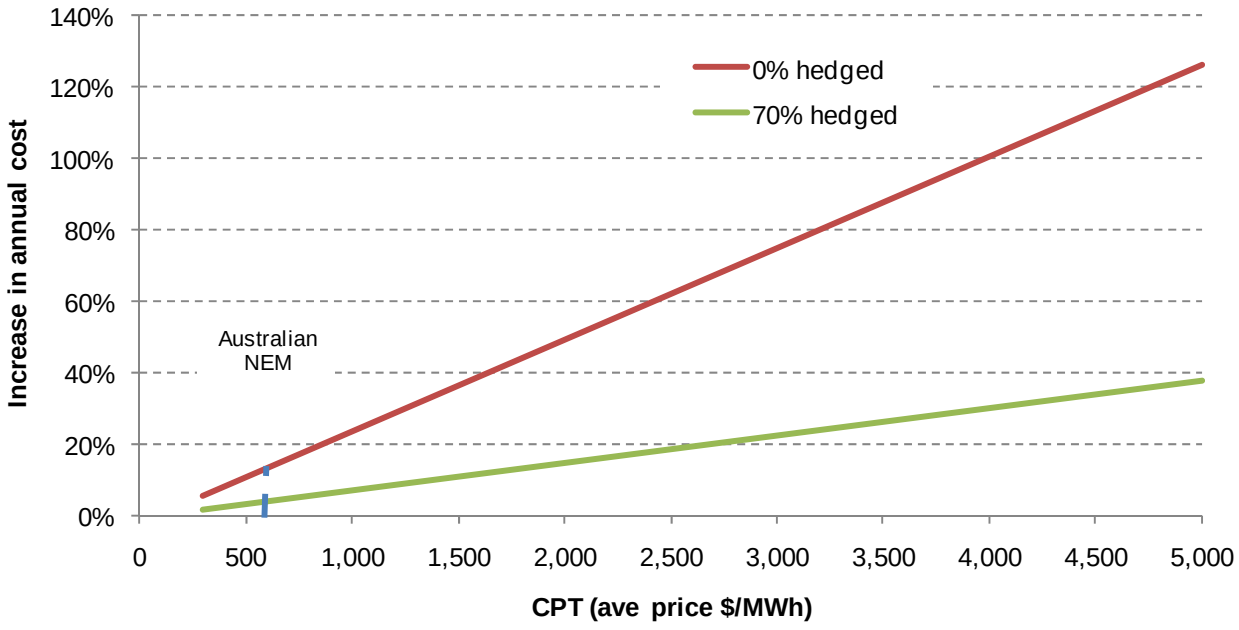
81. To moderate this effect, the CPT price threshold could be raised. The impact of differing CPT thresholds on expected revenues for a resource provider is shown in Table 2.

Table 2: Effect of CPT threshold on revenue for resource provider (4 week event)

CPT threshold ($/MWh)	Effect on spot revenue for resource provider (4 week event)
$ 1,000	-71%
$ 2,000	-47%
$ 3,000	-28%
$ 4,000	-12%

82. While higher CPT thresholds could ameliorate the adverse incentive effects for resource providers, they will also have a significant impact on purchaser risk during a capacity-type event.

Figure 11: Effect of CPT event on annual procurement (7 day event)



83. Figure 8 shows the effect on purchaser risk exposure for higher CPT threshold levels. For a CPT of $3,000/MWh, an unhedged purchaser would accrue around 75% of its annual expected cost in a seven day event. Even if the purchaser were 70% hedged, the increase in costs could be quite significant (around 20%).

84. To offset the effect of a higher price threshold for the CPT (i.e. $3,000/MWh rather than $1,000/MWh), the measurement period could be shortened. In principle, this should help mitigate price risk for capacity-type shortages because the CPT will take effect more quickly.

85. However, in practice it appears that shortening the CPT period may be of limited benefit. Figure 12 shows a hypothetical spot price trace if there was a capacity shortage for a few hours repeated over six days. It also shows the effect of a CPT set at $1,000/MWh and measured over seven days. After day three, the CPT has taken effect and moderated spot prices. Figure 13 shows the same event, but the CPT is set at $3,000/MWh and measured over three days. In this case, the CPT does not have any moderating effect. Indeed, in this example even a one day measurement period would not trigger the CPT because the daily average price is $2,258/MWh.

Figure 12: Effect of CPT set at $1,000/MWh on spot prices (7 day event)

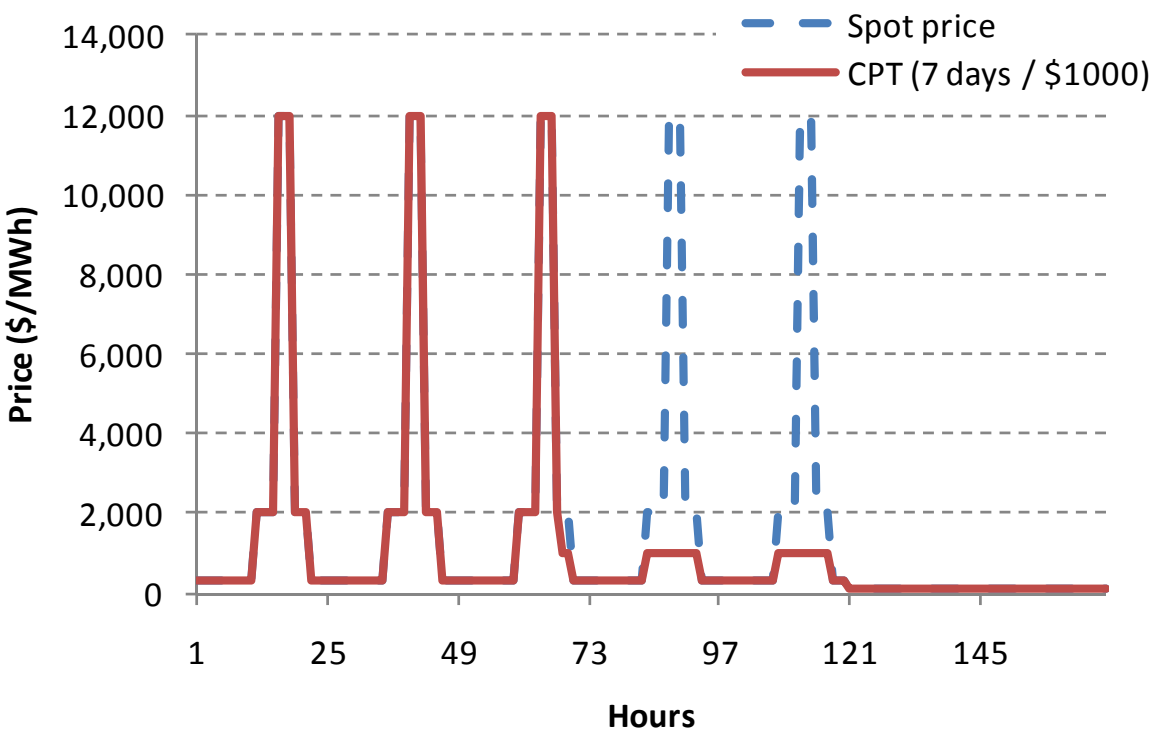
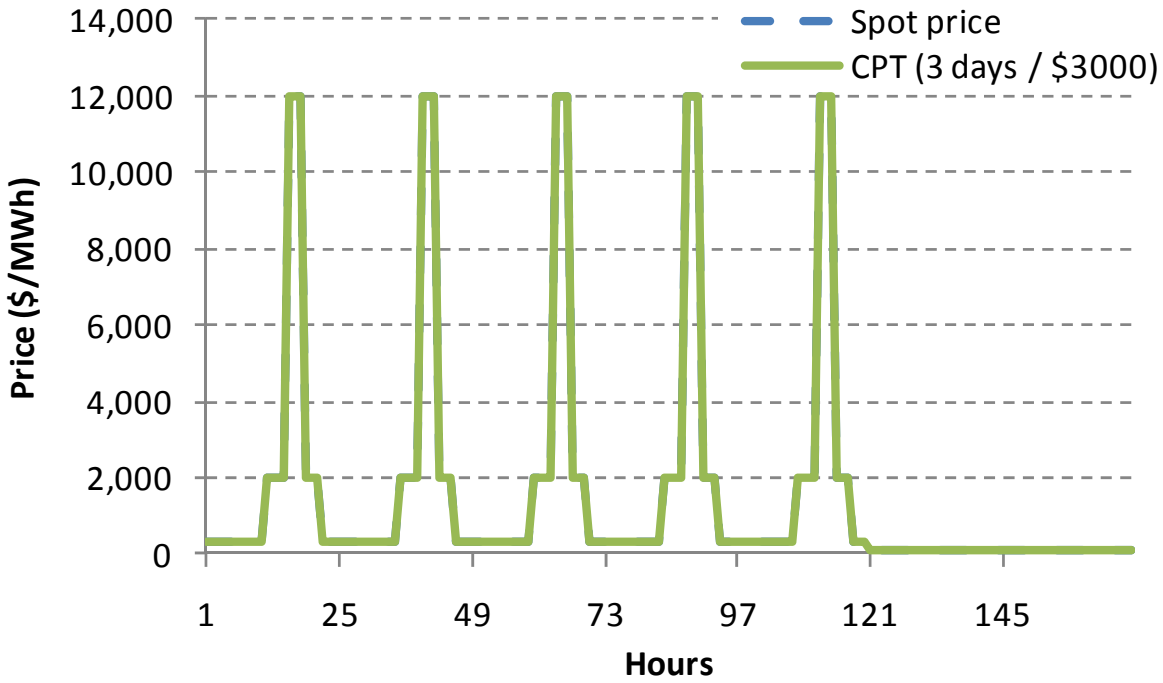


Figure 13: Effect of CPT set at $3,000/MWh on spot prices (7 day event)



86. In summary, the large difference in expected duration between short-term capacity and energy shortfall events means that the situations have very different risk 'tails'. Because capacity events are unlikely to be extended, a 'moderate' CPT can reduce

risk in that context without unduly altering incentives for resource provision. By contrast, because rolling outage events can last much longer, a 'moderate' CPT will have a much greater effect on resource provider incentives.

87. It appears that an important trade-off may exist between the administrative advantages of a single CPT regime, versus the compromise that this will entail for either short term risk amelioration, and/or resource provision during rolling outage situations.

Question 6: What is your view on the relative merits of the administrative benefits of a single CPT mechanism versus the impacts on risk and incentives?

Implementation issues – market pricing algorithm

88. This section discusses some of the implementation issues that would arise with scarcity pricing. In particular, it sets out high level choices on how a conceptual design could be reflected into the market scheduling, pricing and dispatch algorithm (referred to as 'SPD[18]' for short). As will become apparent, there is no 'perfect' option to translate scarcity pricing principles into SPD because it is not possible to observe the actual cost associated with curtailed demand. A range of approaches are possible and each has strengths and weaknesses.

89. Before considering these issues further, it is important to acknowledge there are other implementation issues which are distinct from the SPD formulation. In particular, as noted in earlier meetings, there is likely to be benefit in more closely defining the processes used to determine the need for load curtailment, and the associated processes for communicating this to market participants.

90. The working assumption adopted for this paper is that a clear and workable set of trigger conditions will be in existence, and that the System Operator will be able to use these to determine whether to instruct involuntary load curtailment ahead of real time. Furthermore, for the purposes of this paper, the issuance of such an instruction is taken as the pre-condition for the application of scarcity pricing for the relevant periods/nodes.

Scheduling, pricing and dispatch algorithm

91. SPD takes information on a range of variables including offer prices and quantities for generation and interruptible load, the grid's configuration, and electricity demand.

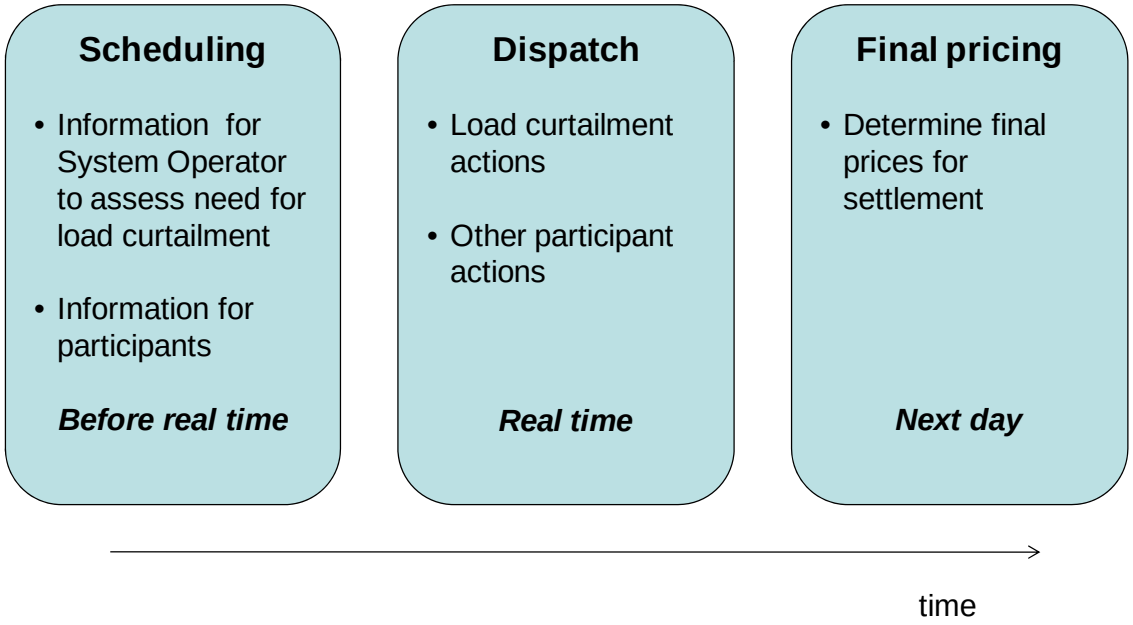
[18] Strictly speaking, SPD refers to the suite of software programmes used for scheduling, pricing and dispatch purposes. The objective function for optimising the system is set out in the market rules. These rules are in turn reflected in the SPD software. This paper uses the term 'SPD' loosely to refer to the processes and arrangements used to determine final pricing.

It uses this information to 'solve' to find the least cost way of meeting aggregate electricity demand across the system. This process is designed to take account of issues such as the trade-off between energy costs, reserve costs, constraints and transmission losses.

92. The process of finding the best aggregate 'solve' also establishes the marginal value of electricity at each node on the system – more commonly referred to as nodal prices.

93. SPD is used across three broad timeframes to collate and process information, as shown in Figure 14[19]. In the scheduling timeframe, SPD is used for planning. In the dispatch timeframe it is used to give instructions to generators, demand participants, and network providers, and in the final pricing timeframe to calculate the payments to be made between parties.

Figure 14: Types of decisions and operational timeframes



94. While there are clear linkages between these timeframes, this paper focuses largely on the last time interval where final prices are determined, as scarcity pricing ultimately operates by changing settlement prices. Of course, the other timeframes are extremely important. For example, participants need high quality pricing information in the pre-dispatch timeframe to plan generation and demand decisions, and to assess the likely outturn for final prices. However, these linkages can be considered once possible changes to the final price process have been determined.

[19] Real-time pricing is another schedule that occurs during "real-time". Run at the end of the 5 minute interval, it provides participants with prices relating to the real time dispatch conditions. These prices provide an indication of 'Final Prices', which are the actual prices paid and received by participants – i.e. the prices used for settlement purposes.

95. To assist in considering different potential SPD formulations, a list of *possible* design attributes for scarcity pricing has been prepared. The current list is:
    - a value of lost load (VOLLu) would be applied for grid emergency ('un-notified') demand curtailment events;
    - a lower value of lost load (VOLLn) would applied for rolling outage ('notified') demand curtailment events;
    - the value of VOLLu would be a market price cap during non-scarcity periods; and
    - there would be a cumulative price threshold (CPT), after which a lower price cap would apply until the CPT is no longer breached.
96. The list does *not* include any minimum geographic threshold for applying scarcity pricing at this point. This has been excluded to ensure the pricing methodology can be generalised to address nodal, regional, island or national outages if required.
97. Before considering these options, it is useful to recall the key drawback with current arrangements. The issue of concern is that final prices may not reflect the marginal value of electricity in a forced curtailment situation. This arises because SPD determines final prices on the basis of generator offers and *metered* load. Because metered load by definition will exclude the portion of demand that is curtailed, SPD determines prices as if the system had not experienced any shortfall in supply, and final prices are based on generator offers adjusted for losses and constraints.

Broad options for final price formation

98. Analysis to date indicates there are two broad options that could be used to implement scarcity pricing/price caps. They are:
    - Option 1 Final Pricing – apply scarcity prices for demand curtailment or price caps within SPD. In essence, this would be achieved by placing a notional VOLL resource provider at each node. The provider would offer its resource (i.e. demand curtailment) at the VOLL price. In a scarcity situation at any node(s), the resource would be treated as having been 'dispatched' by SPD. Likewise, the provider at any node(s) would be dispatched if the normal application of the pricing algorithm would lead to prices being above VOLL. This is how the price cap would be implemented; or
    - Option 2 Final Pricing – apply scarcity prices for demand curtailment or price caps as a post-process to final pricing. In effect, this would over-write the final prices determined by the normal application of SPD. Instead, prices at some nodes would be determined in accordance with a set of predefined rules. The key rules for this option are that prices at grid injection points would be set to VOLL in any area affected by forced demand curtailment. To ensure that receipts from

purchasers cover payments to generators[20], prices at offtake nodes in that area would be set at VOLL plus an amount to reflect average transmission losses in that area[21]. Likewise, prices at any node could not exceed the price cap.

99. For readers wishing to explore the options in more detail, a fuller description is provided in Appendix 1. The Appendix also shows illustrative price patterns that would result across grids nodes for different curtailment or price cap events.

100. Table 3 provides a summary of how the two options compare in terms of their general effect on pricing, and their ability to allow for different potential features in a scarcity pricing regime.

[20] To avoid negative settlement surpluses in industry jargon.

[21] A variant would be to adjust prices within the scarcity region according to a published loss factor.

Table 3: Comparison of alternative final pricing options

Feature/issue	**Option 1 – Within SPD**	**Option 2 – Post Process**
Allows for scarcity to be signalled at node, region, island or national level	Appears feasible	Appears feasible
Allows nodal price differences to be signalled *between* scarcity areas and rest of grid	Yes	Yes
Allows nodal price differences to be signalled within scarcity areas	Yes in principle – though it depends on interpretation of 'true' picture (see below)	No[22]
Allows separate scarcity values for grid emergencies and rolling cuts	Yes	Yes
Allows for price cap	Yes. Offer price cap would be required to reduce potential constrained on payments	Yes. Offer price cap would be required to reduce potential constrained on payments
Allows for CPT	Appears feasible – but complexity rises if applied below aggregate level	Appears feasible – but complexity rises if applied below aggregate level
Constrained-on payments	Potential for sizeable constrained on payments to ensure revenue adequacy	Yes – but expected to be lower than Option 1

[22] Locational differentiation could be achieved if a loss factor were applied. This however could then affect the level of constrained on payments for this option.

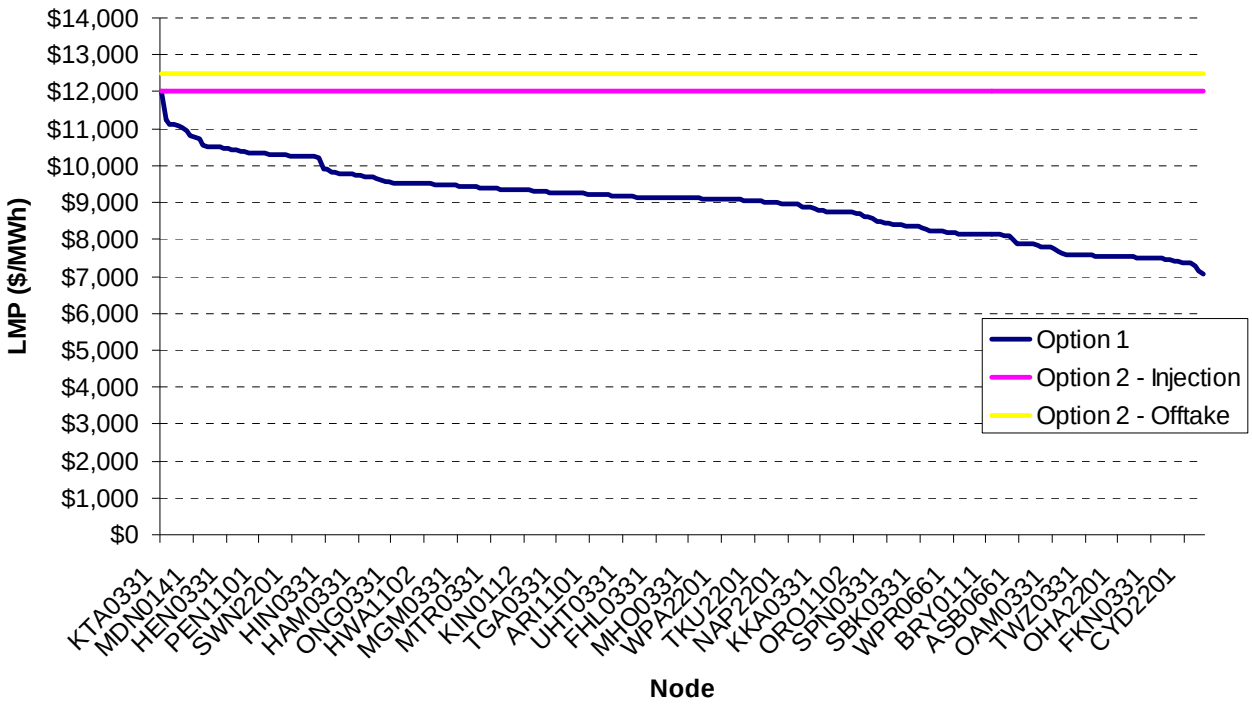
101. As shown in Table 3, the key differences between the approaches are the effect on nodal prices within an area experiencing scarcity, and the potential level of constrained on payments. These are discussed below.

Nodal price differences

102. Both options will reflect nodal prices differences *between* areas affected by curtailment and the rest of the grid. However, in Option 1, there will also be nodal differences reflecting marginal losses *within* the area affected by scarcity. Under Option 2, there are no differences, except that prices at injection and offtake nodes differ to the extent of average transmission losses within the grid area affected by scarcity[23].

103. This is shown by Figure 15 and Figure 16 respectively which show illustrative examples of nodal price patterns for national and localised events respectively[24].

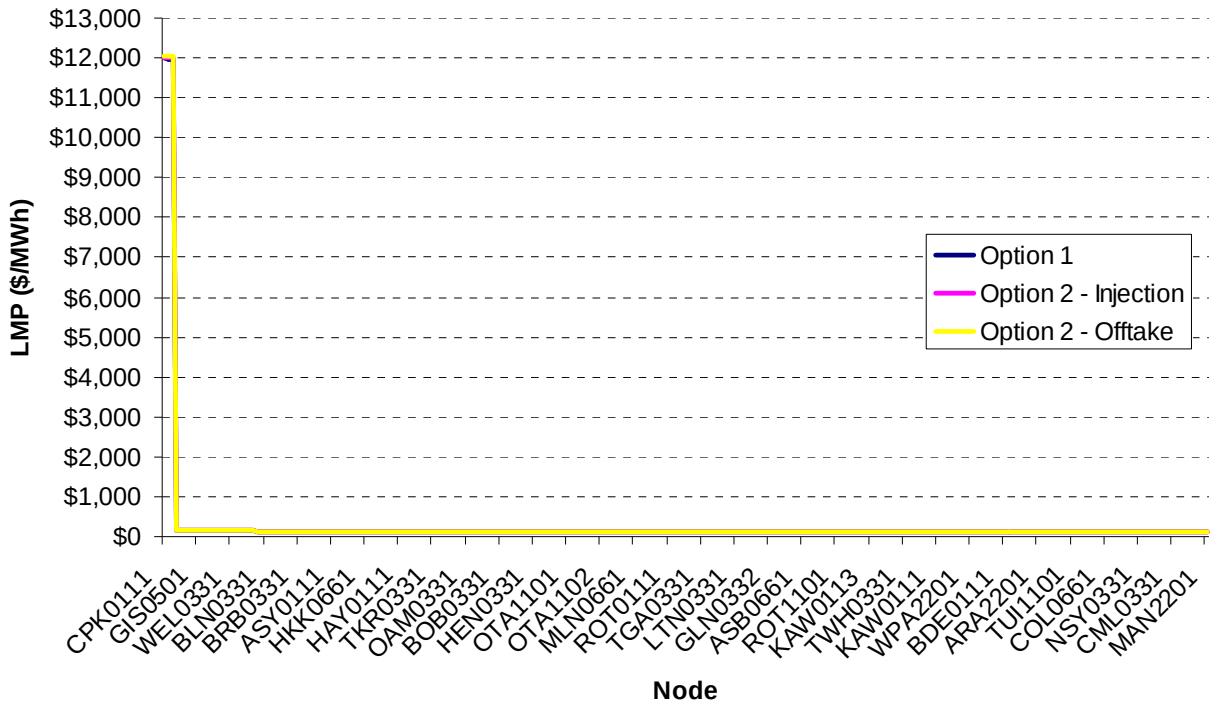
Figure 15: Nodal prices for national curtailment event



[23] As noted above, a variant of Option 2 could be adopted where a loss factor is applied to nodes within the scarcity region to provide some locational differentiation.

[24] For illustrative purposes, these examples assume a scarcity price for grid emergency demand curtailment of $12,000/MWh. The examples are used to illustrate the effects of the different options. Note that no decision has been made on the minimum geographic threshold for triggering scarcity pricing.

Figure 16: Nodal prices for localised curtailment event



104. Under Option 1, a variation is apparent across different nodes reflecting the effects of marginal transmission losses. For the national event, prices at the Kaitaia node would have been $12,000/MWh, and there would have been a declining gradient of prices reaching their lowest point in the lower South Island at around $7,000/MWh.

105. In this case, Kaitaia has the highest price since marginal reduction in demand at this location is worth more to the system than at any other location in the network due to the reduction in transmission losses. In other words, curtailing demand at any other location will require an even larger cut to compensate for transmission losses. The node experiencing the highest transmission losses will vary. For example, during periods of southward transmission flow, the location would probably be in the lower South Island.

106. Similar principles apply for the localised curtailment example, although the difference is less extreme because the outage only affects three nodes (Wilton, Kaiwharawhara and Central Park)[25]. Because of the physical characteristics of the grid between these nodes, the effect of marginal losses is very limited.

107. Under Option 2, prices are uniform across the grid for a national curtailment event, except for the difference between grid injection and offtake nodes to reflect average

[25] As noted earlier, this example of a localised application of scarcity pricing is included for illustrative purposes. No decision has been made on the minimum geographic threshold for the application of scarcity pricing, i.e. whether scarcity pricing will apply for outages affecting a single node etc.

losses[26]. Likewise, in the localised event, prices at Wilton, Kaiwharawhara and Central Park are uniform, and prices outside this scarcity 'region' are much lower, and reflect the normal effects of marginal losses.

108. Neither option yields prices that are an absolutely 'correct' representation of the real world. In reality, the marginal cost of demand reduction is unique at every node, and is influenced by factors such as the time of day, the depth of the interruption and the processes that were interrupted. Since demand reduction is represented as a single VOLL cost in the model, in Option 1 SPD uses loss and constraint effects to determine the incremental cost to the system of load reduction at a given node. Therefore for this event, a 1MW demand reduction at Kaitaia is equivalent to a ~1.6MW demand reduction at Invercargill due to the transmission loss effect.

109. Put another way, SPD treats load at all locations as being equally valuable, except for any differences caused by transmission losses or binding constraints. However, in the real world, demand cuts are likely to be spread in a (relatively) even fashion across all nodes in the scarce region irrespective of transmission losses (there is no point in cuts outside the region if there are binding transmission constraints). This 'equal pain' approach presumably reflects a judgement that other factors are more important than transmission losses in determining which load should be cut.

110. This logic tends to support the approach in Option 2 where injection and offtake prices are respectively set to uniform levels in the area experiencing curtailment. However, this approach also has some weaknesses. In particular, the difference between injection and offtake prices reflects average transmission losses (otherwise there is a settlement deficit). However, this can lead to counter intuitive effects, such as price difference between physically adjacent grid injection and offtake points.

111. Another consideration is the extent to which either option would interact with proposed locational hedge arrangements. Like the status quo, Option 1 would generate loss rentals within the scarcity region (however large in geographic size), and these would be a potential revenue source to fund locational hedging instruments.

112. Under Option 2, there would be no loss rentals generated within a region experiencing scarcity. This means the rentals would not be available as a revenue stream for locational hedge instruments inside that region. However, the need for instruments to address nodal price differences within that region is arguably addressed by the fact that nodal prices in the region would be uniform, other than the difference between injection and offtake prices.

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[26] Note that the charts are not strictly comparable because the method chosen for applying scarcity prices can affect the assessed scarcity price itself – whether it is set by reference to the cost of non-supply to customers, or set by reference to the expected revenue requirements of last resort resource providers and a target level of security. This effect is not taken into account at this stage of the analysis.

113. In short, it appears that either approach might be compatible with proposed locational price risk arrangements. Of greater significance is the decision about what geographical threshold to adopt for scarcity pricing. However, that decision does not rest on the approach taken to implementing changes to final prices, or vice versa.

Constrained on compensation

114. Another key difference between the options is that Option 1 has a greater potential for constrained on payments. This type of payment is made to generators that are dispatched to run in real time, but whose offer price is above the final price at the injection node. In these cases, constrained on compensation is calculated as the difference between the generator offer price and the final price at the node, multiplied by the volume of generation dispatched in these tranches where the offer price is greater than the final price at the node.

115. Constrained on payments are currently recovered from purchasers as a $/MWh uplift charge that is averaged across all consumption in the relevant trading period. In the national curtailment example noted above, a South Island generator offering at close to VOLL would be paid around $7,000/MWh based on final prices, and a further $5,000/MWh in constrained on compensation, solely to address the effect of transmission losses. The potential for such large differences gives rise to a number of issues:

- Constrained on compensation amounts could be a sizeable proportion of settlement flows during a period of scarcity pricing (or when prices are capped);
- Purchasers are likely to find it difficult to hedge their exposure to constrained on compensation payments; and
- Constrained on payments are recovered on an average basis across all purchasers. For any event other than a national event, this means that parties outside the scarcity region would share in meeting the cost of constrained on compensation. This is inconsistent with the general principle of providing the scarcity price signal to parties in the scarce region. It may be possible to address this issue by altering the basis on which constrained on payments are calculated. Unless this occurs, it would be likely to dampen scarcity price signals.

116. While all these issues are relevant, it is also important to note that the potential for large constrained on compensation payments during an energy shortfall already exists under current arrangements. Indeed, because final prices under present arrangements are calculated on the basis of metered demand (i.e. ignoring the effect

of any forced curtailment), the difference between offer prices and final prices could be higher than Option 1[27].

Further work on final pricing options

117. Ideally, the 'true' economic effect of scarcity pricing would be reflected into pricing arrangements. However, this would require knowledge of the marginal costs of demand curtailment at each node during an event, and these figures cannot be observed.

118. For this reason, the market model will be an approximation of reality, and choices are required about how to treat factors such as transmission losses. This section has presented an initial discussion of the two broad approaches, but neither shows a clear advantage. To assist in determining a preferred option, further work will focus on:

- considering the options under a range of market operating conditions based on historical as well as hypothetical cases;
- considering variants of the implementation options;
- considering the price signals at each node, compared to the desired incentive;
- considering the effects on nodal price risk, and interaction with the locational price risk instruments;
- estimating the potential magnitude of different options on constrained on payments;
- considering in more detail the approach taken in some other markets to these issues.

Question 7: What is your view of the broad alternatives for implementing scarcity pricing within the market pricing engine?

Advice sought from SPDBTG

119. Advice is sought from SPDBTG on the following questions.

Question 1: What is your view of setting the scarcity price for rolling outages as a proportion of the scarcity price for grid emergency demand curtailment?

Question 2: What is your view on how the cost of curtailment will be affected by the depth/coverage of a rolling outage, and how might these costs be defined further?

[27] If one believes that the introduction of a cap within the market increases the likelihood of participants offering in the vicinity of the cap then it is likely that the probability of constrained on payments would increase both during scarcity and non-scarcity situations.

Question 3: To what extent do you agree that rolling outages are likely to incur less cost to electricity users than cuts initiated under grid emergency arrangements?

Question 4: What further analysis could be used to determine a scarcity price to apply during rolling outages?

Question 5: What is are the key factors that determine whether a price floor during public conservation campaigns will be beneficial, and what analysis can be undertaken to assess these factors?

Question 6: What is your view on the relative merits of the administrative benefits of a single CPT mechanism versus the impacts on risk and incentives?

Question 7: What is your view of the broad alternatives for implementing scarcity pricing within the market pricing engine?

APPENDIX 1 – OPTIONS FOR FINAL PRICING

120. This appendix describes two broad options for incorporating scarcity pricing/price caps within the final pricing process. The appendix shows the effect of each option on final prices for a range of illustrative events. These range from national curtailment situations, through to events where curtailment is only instructed for a few nodes. It is important to note that no decision has been made on the minimum geographic threshold for the application of scarcity pricing. As a result, scarcity pricing may not be applied for some of the events that are illustrated.

121. Both of the final pricing options should be regarded as working models that are being put forward to facilitate discussion and elicit feedback. Further detailed work is required before either model (or a variant of them) could be implemented.

Option 1- Final pricing formulation

122. This option incorporates scarcity pricing/price caps within SPD itself, and therefore preserves locational signalling based on nodal price differences to a large extent[28].

123. This option retains the existing final pricing process as stage 1. This stage is effectively used to establish prices for any nodes that were unaffected by curtailment, i.e. any nodes that are upstream of binding constraints in situations where scarcity is localised. Prices at such upstream nodes should not be changed by the application of scarcity pricing[29].

124. The option includes a second stage that is used to apply the scarcity prices or market price cap to the relevant nodes if required. An outline of the process in flow diagram form is shown in Figure 17.

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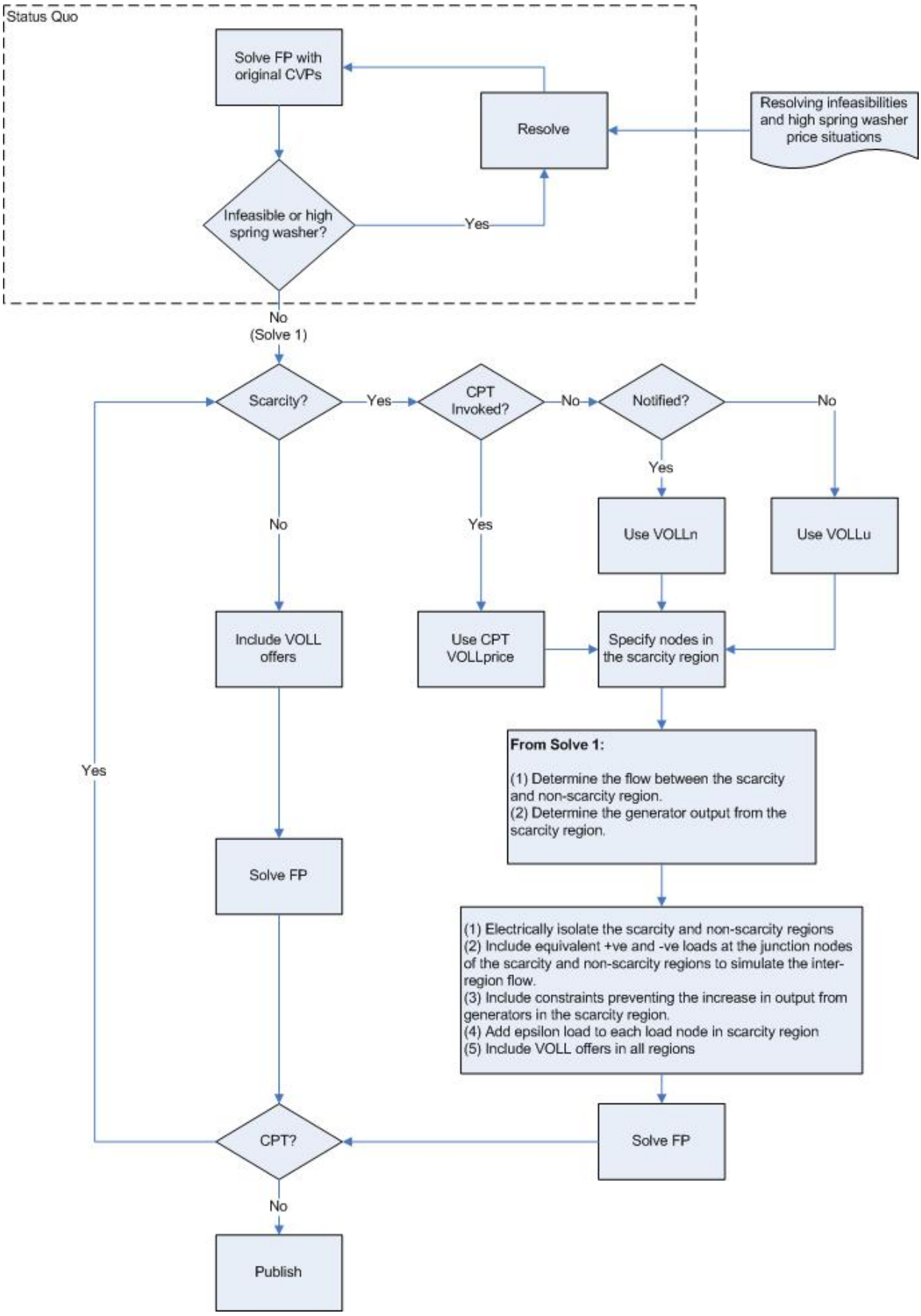
[28] The reason for this qualification is discussed later.

[29] While the stage 1 solve should correctly identify the nodes which experienced scarcity in most cases, this may not always hold. For example, it is possible that absent demand curtailment, a binding constraint will exist on the HVDC link, and forced load shedding is required for North Island customers. When the stage 1 solve is run for final pricing, SPD may not 'recognise' the HVDC constraint because it uses actual metered demand, and load shedding in the North Island may have been sufficient to relieve the constraint. Accordingly, SPD would apply scarcity pricing over all of New Zealand – even though the physical problem in real time had been confined to the North Island. Further thought is being given to this issue. Another issue being considered is the method for identifying the scarcity region during rolling cuts. The same general principles apply – only prices inside a region where demand curtailment is occurring should be affected – but a single time period solve of SPD may not provide the required information.

Figure 17: Flow diagram Option 1



125. If a scarcity situation occurred (e.g. it was known that demand curtailment had been instructed the previous day for a node or region), then a set of steps are followed based on the results from the stage 1 solve. These are used to prepare the second final pricing solve which includes the application of scarcity pricing. The steps are as follows:

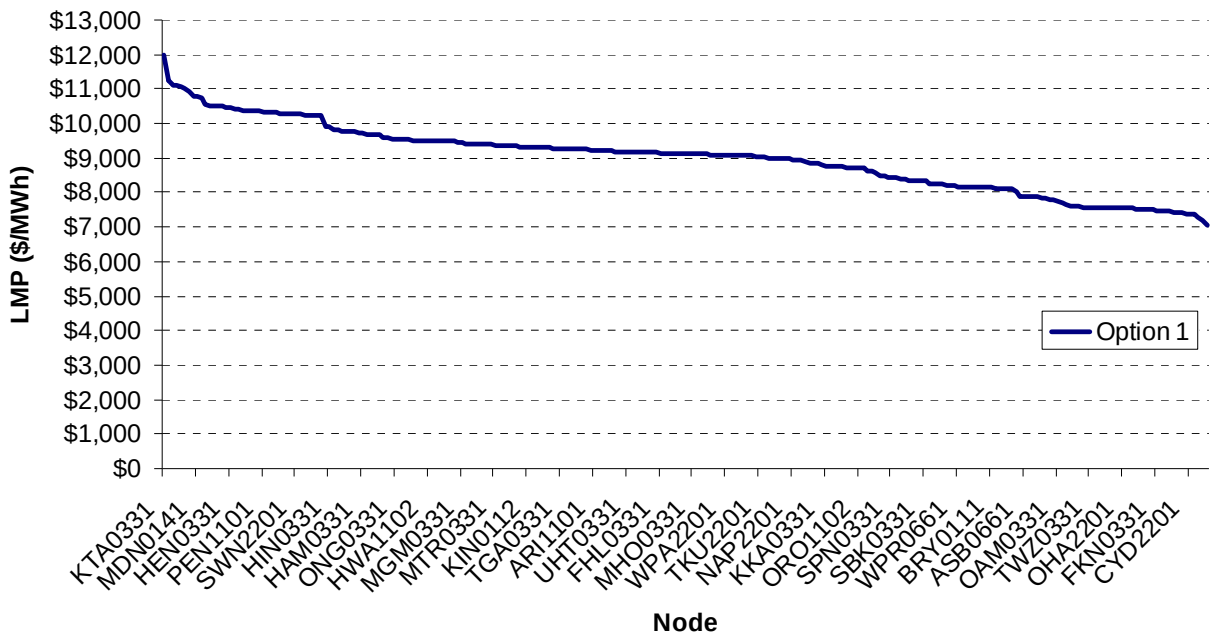
- the branches between the scarcity and non-scarcity region(s) are opened and replaced by equivalent positive and negative loads to simulate the inter-region flow from Solve 1;
- generators within the scarcity node/region cannot exceed their output from Solve 1;
- a small load (~0.0001 MW) is included at each load node within the scarcity region; and
- a 'notional resource provider' offering at VOLL is included at each load node within the second solve.

126. The addition of the small amount of load in the second solve will trigger the VOLL offers resulting in VOLL prices at nodes in the defined scarcity region. Furthermore, the pattern of prices across nodes for any outage affecting more than one node would include the marginal loss effects.

127. This is illustrated by Figure 18 which shows the pattern of nodal prices across New Zealand, had there been a nationwide shortage event and VOLL was set at $12,000/MWh[30].

[30] This figure is used for illustrative purposes.

Figure 18: Option 1– NZ wide curtailment event



128. On 5 October 2009 there was a shortage of energy and instantaneous reserve offers. This was actually only applicable to the North Island. During dispatch the North Island reserve requirements were relaxed. This run is conducted assuming that system-wide curtailment was conducted in TP42.

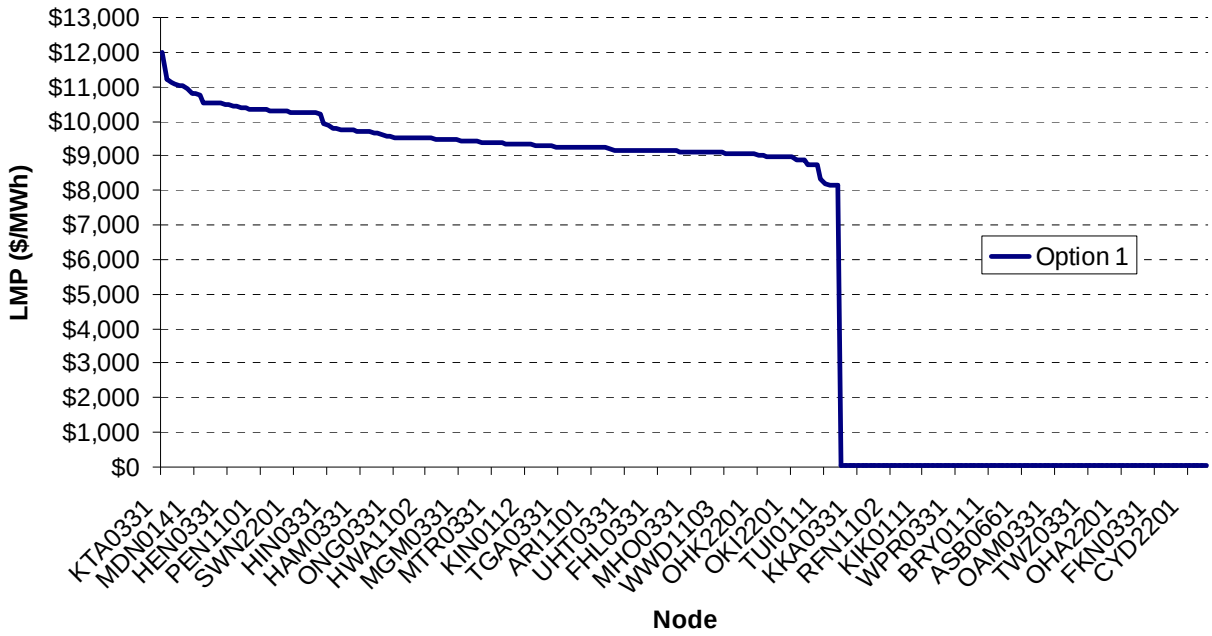
129. Prices at the Kaitaia node would have been $12,000/MWh, and there would have been a declining gradient of prices reaching their lowest point in the lower South Island at around $7,000/MWh. The differences reflect the effect of marginal transmission losses between different points in that period. In economic terms, SPD is looking for the best location at which to curtail demand (i.e. dispatch the VOLL provider). SPD chooses Kaitaia because it minimises the aggregate volume of curtailment that is required. Curtailing demand at any other location will require an even larger cut to compensate for losses.

130. In this case, the Kaitaia node is chosen as the best location for dispatch of the notional VOLL resource provider. Depending on the grid configuration and the relative locations of generation and load, SPD might sometimes find it more efficient to choose other locations as the point to utilise the notional VOLL resource provider. For example, during periods of southward flow, the location would be in the South Island.

131. While the example illustrates the effect for a nationwide curtailment, the same principles apply for more localised curtailment events, whether for an island, region, or a handful of nodes. In each case, the differences in spot prices between locations will reflect the effect of marginal transmission losses and any binding transmission constraints.

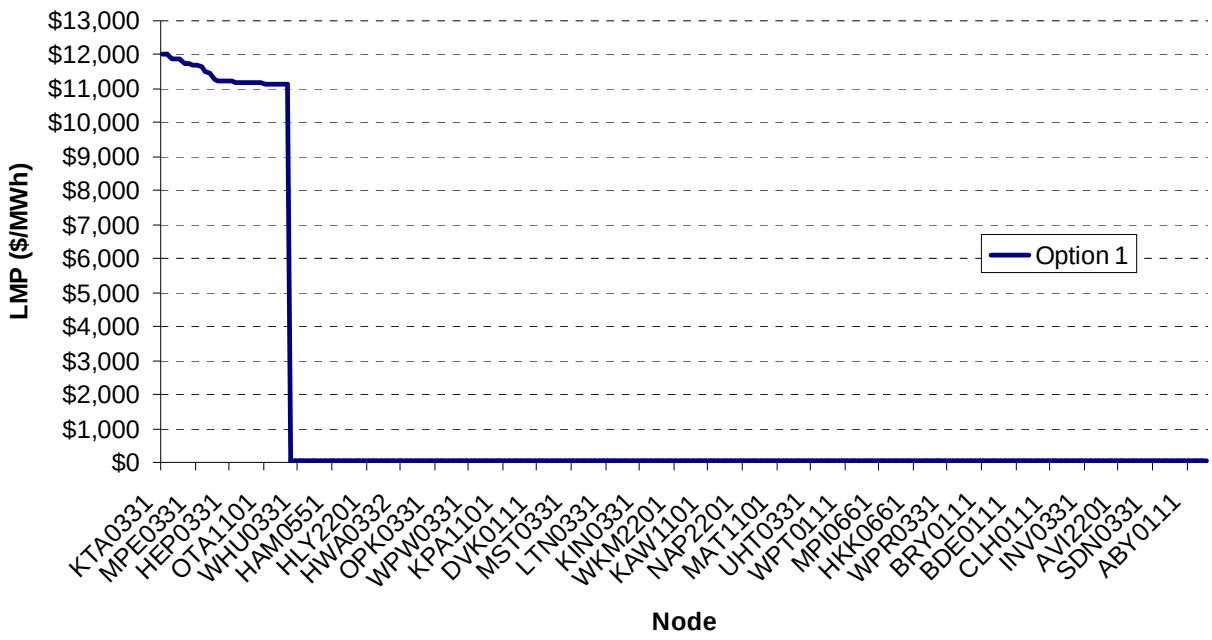
132. Figure 19 shows the same 5 October 2009 example but assuming only North Island load curtailment was conducted in TP42 In this case, there is a large difference between the islands (reflecting the constrained link and shortage in the North Island), but within each island the pattern of prices reflects marginal losses.

Figure 19: Option 1– North Island curtailment event



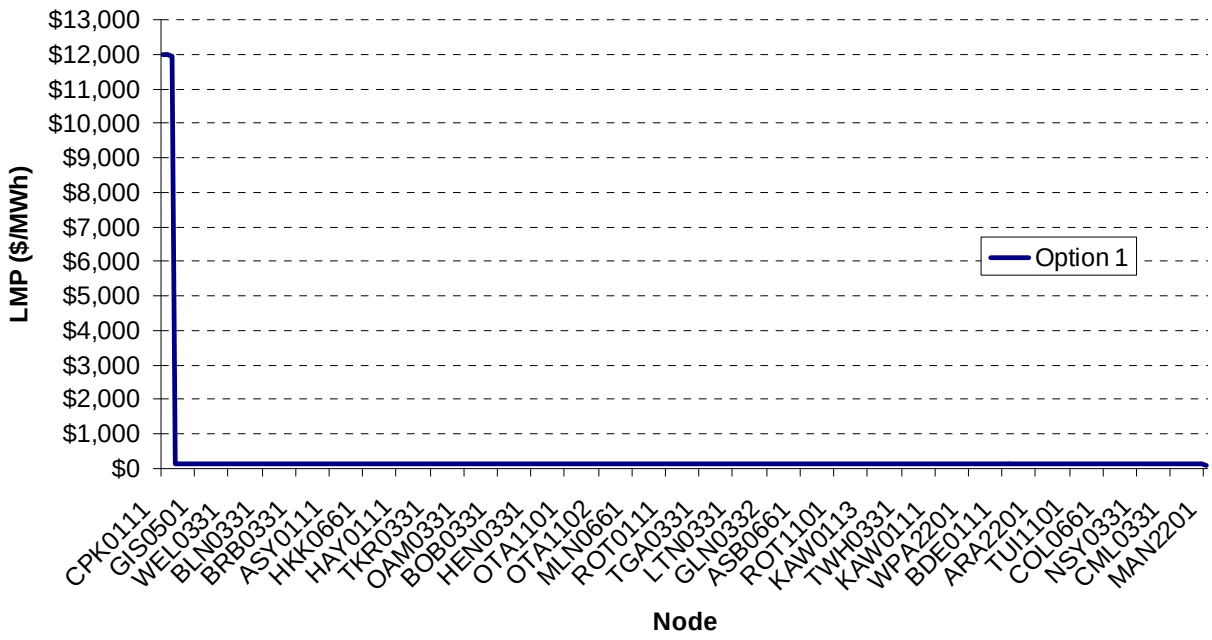
133. Figure 20 shows an example where load shedding is confined to the upper part of the North Island. In this case, there is a large difference between the upper North Island and rest of New Zealand (reflecting the constraint), but within each broad region the pattern of prices reflects marginal losses.

Figure 20: Option 1– Upper NI curtailment event



134. Figure 21 shows an example where load shedding is confined to three nodes – Wilton, Kaiwharawhara and Central Park – all in the Wellington area. In this case, there is a large price difference between these nodes and the rest of the country. Although it is not apparent from the scale, the effect of losses is also preserved within each of the scarcity (three Wellington nodes) and non-scarcity regions (rest of New Zealand).

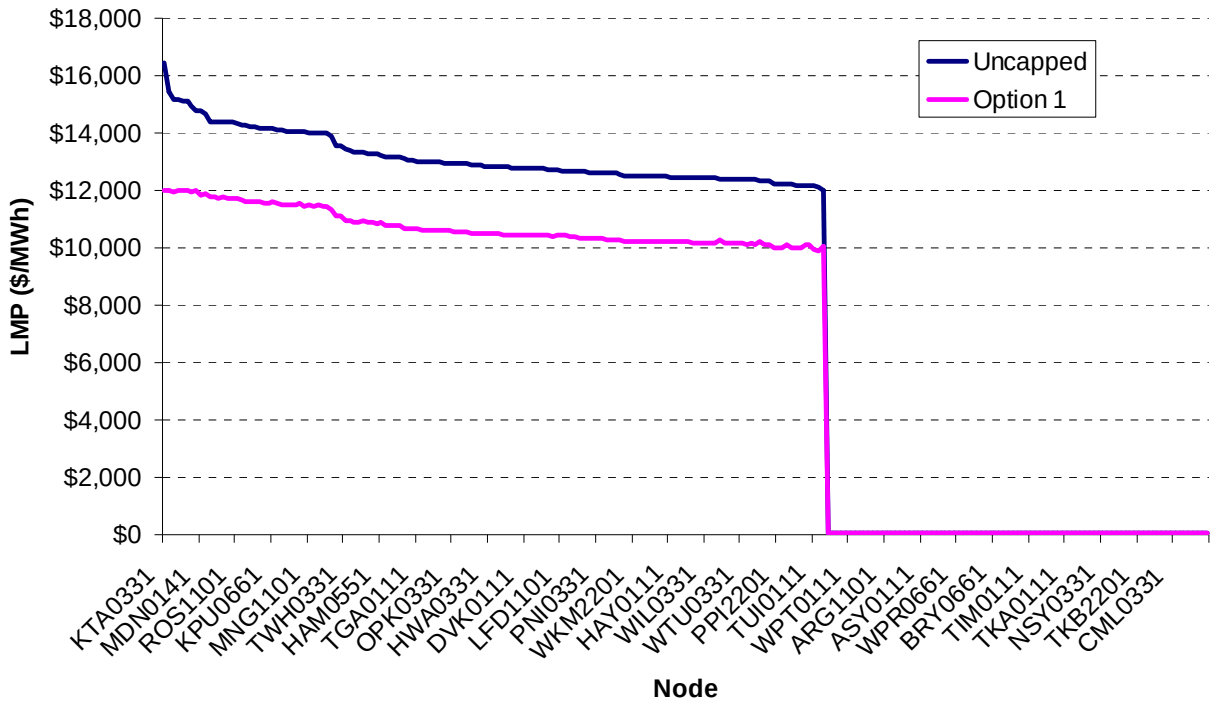
Figure 21: Option 1– Curtailment event at Wilton



135. The preceding discussion of Option 1 has focussed on how scarcity pricing could be implemented. The formulation can also be used to introduce a market price cap through the use of the notional VOLL resource providers sited at each offtake node.

136. These would cap the energy prices at offtake nodes. The prices produced from the Stage 2 solve would reflect the effect of losses and any binding constraints. This is illustrated by Figure 22, which shows the effect if a central North Island generator was the marginal provider in the North Island with an offer price at VOLL. It is important to note that this mechanism would only cap energy prices. It would be possible for instantaneous reserve prices to be higher than energy prices, unless they were also capped. A cap mechanism for instantaneous reserves (which appears to be common where energy prices are capped) could be implemented in a similar manner, but is not considered further in this appendix.

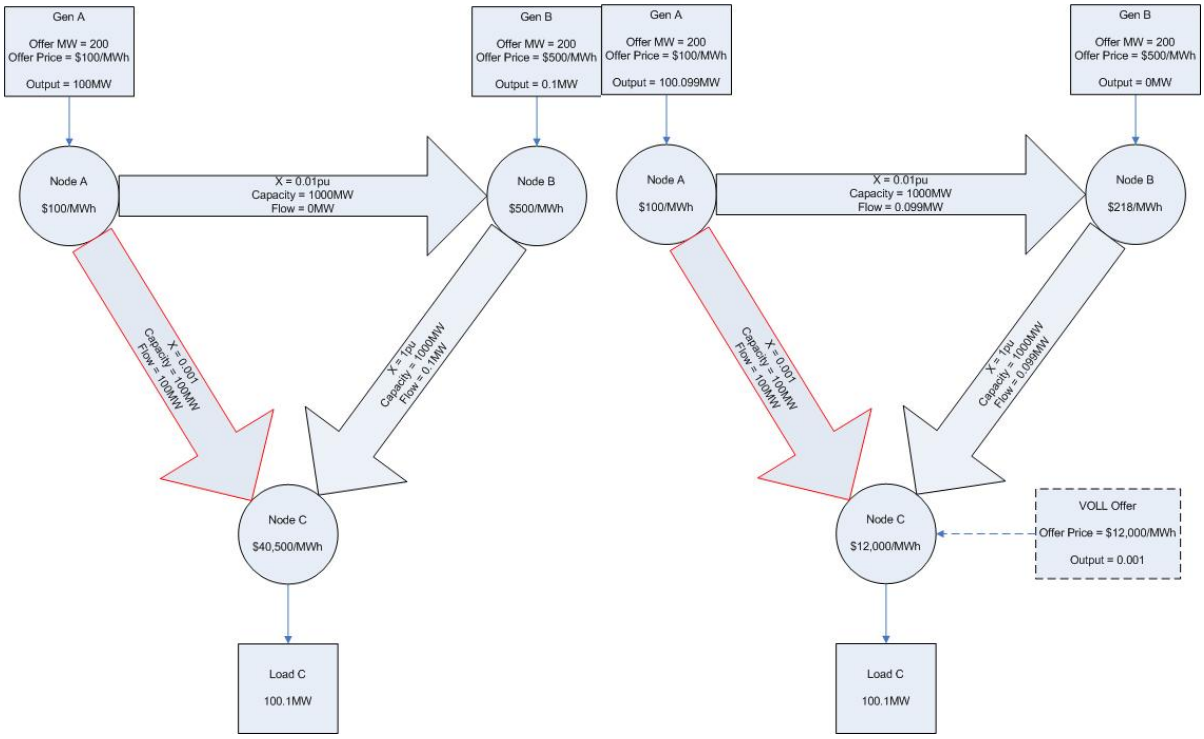
Figure 22: Option 1– Effect of price cap for NZ



137. Option 1 would also have the effect of capping energy prices at any node due to high spring washer effects. This is illustrated by Figure 23 which shows the price pattern that would arise for a simplified representation of a spring washer example[31]. The spring-washer effect is driven by the relative impedance of the constrained and unconstrained branches and the costs involved in supplying the load across these parallel paths. A marginal change in load at Node C results in a large change in generation cost to ensure that the constrained link limit is not violated. With the introduction of the notional VOLL offer, the price and the load node (Node C) in this example is prevented from rising above the local VOLL price. This results in a small increment of output from the notional VOLL generator.

[31] This example is an adaptation of that presented to illustrate spring-washer effects from "On Spring Washers, Constrained Dispatch and Dispatch Model Sensitivity' from the EPOC Winter Workshop, 2006.

Figure 23: Option 1– Effect of price cap in spring washer situation



138. An important aspect to note with Option 1 is the potential for 'constrained on compensation' payments to arise. This type of payment is made to generators that are dispatched to run in real time, but whose offer price is above the final price at the injection node. In these cases, constrained on compensation is calculated as the difference between the generator offer price and the final price at the node, multiplied by the volume of generation dispatched in these offer tranches where the offer price is greater than the final price. Constrained on payments are recovered from purchasers as a $/MWh uplift charge that is averaged across all consumption in the relevant trading period.

139. Under Option 1, there is potential for such payments to arise in both scarcity situations and if the market price cap mechanism is triggered. In the examples shown in Figure 18 (scarcity price event) and in Figure 22 (market cap event) a generator in the central North Island offering at VOLL would qualify for a constrained on payment because the local node price would be below its offer price. In this case, the difference would be around $2,500/MWh, creating potential for a significant level of constrained on payments[32].

140. However, it is important to note that this potential also exists under current arrangements. Indeed, because final prices under present arrangements are calculated on the basis of metered demand (i.e. ignoring the effect of any forced

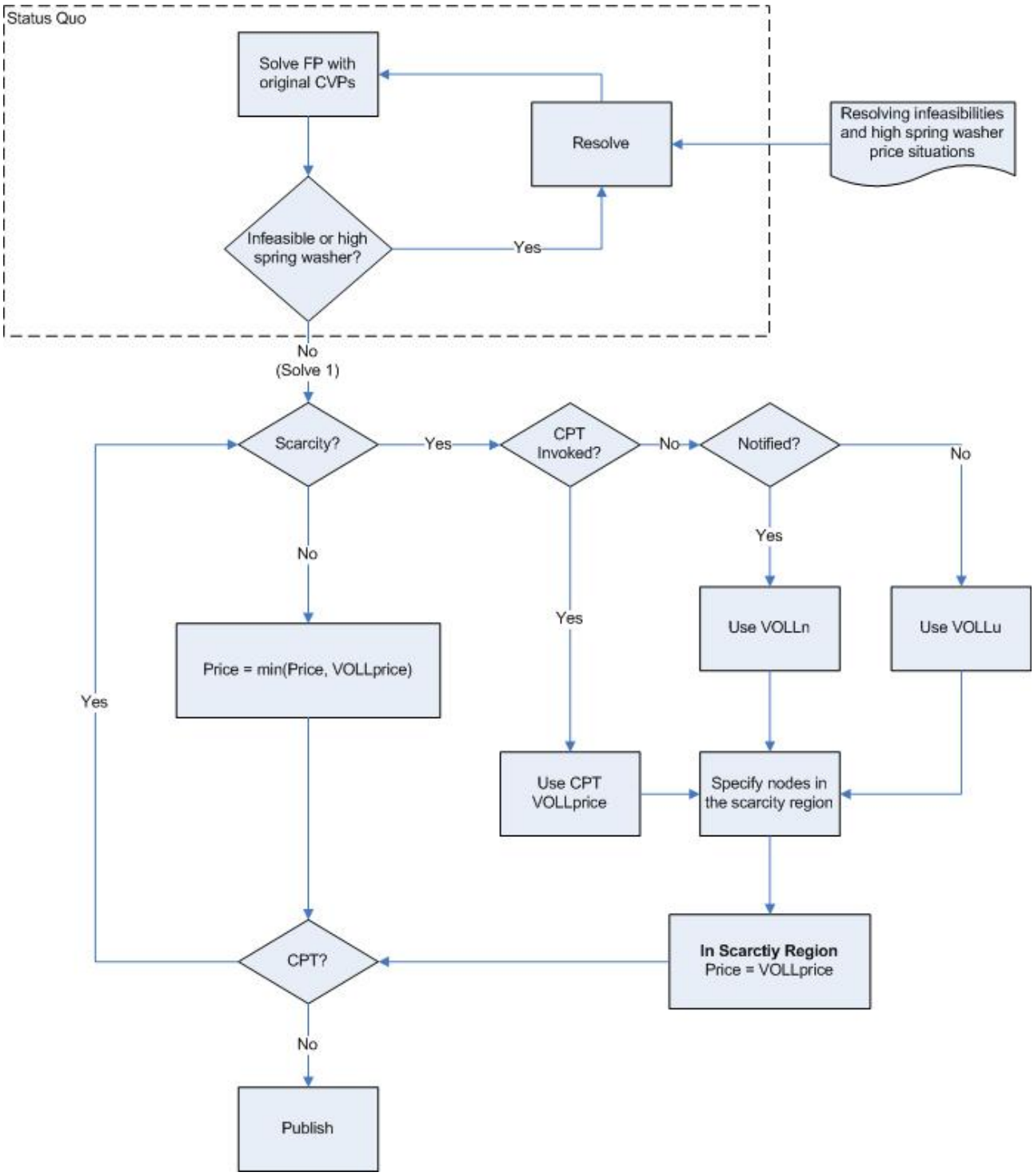
[32] This holds even if there is a cap on offer prices which is set at the level of VOLL.

curtailment), the difference between offer prices and final prices could be higher. This would create an even larger constrained on payment, all other things being equal.

Option 2 - Final Pricing formulation

141. This option also retains the existing final pricing process as stage 1. Again, this stage is effectively used to establish prices for any nodes that were unaffected by curtailment. This option has a second stage that involves post processing of prices to either apply the scarcity prices at the affected nodes, or to apply the market price cap. The post-processing of prices would not seek to preserve nodal price differences within the scarcity region, and this implies that only a single solve is needed. An outline of the process in flow diagram form is shown in Figure 24.

Figure 24: Flow diagram Option 2



142. In a forced demand curtailment situation, the scarcity price value could be applied to both grid injection and offtake nodes. This however could result in insufficient revenue collected from grid offtake nodes within the scarcity region to pay for transmission losses within the region. To cater for this two sub-options could be considered::

- set grid injection prices to VOLL, and grid offtake prices to VOLL multiplied by (1 + average losses[33]) in the affected area;
- set grid offtake prices to VOLL, and grid injection prices to VOLL divided by (1 + average losses) in the affected area.

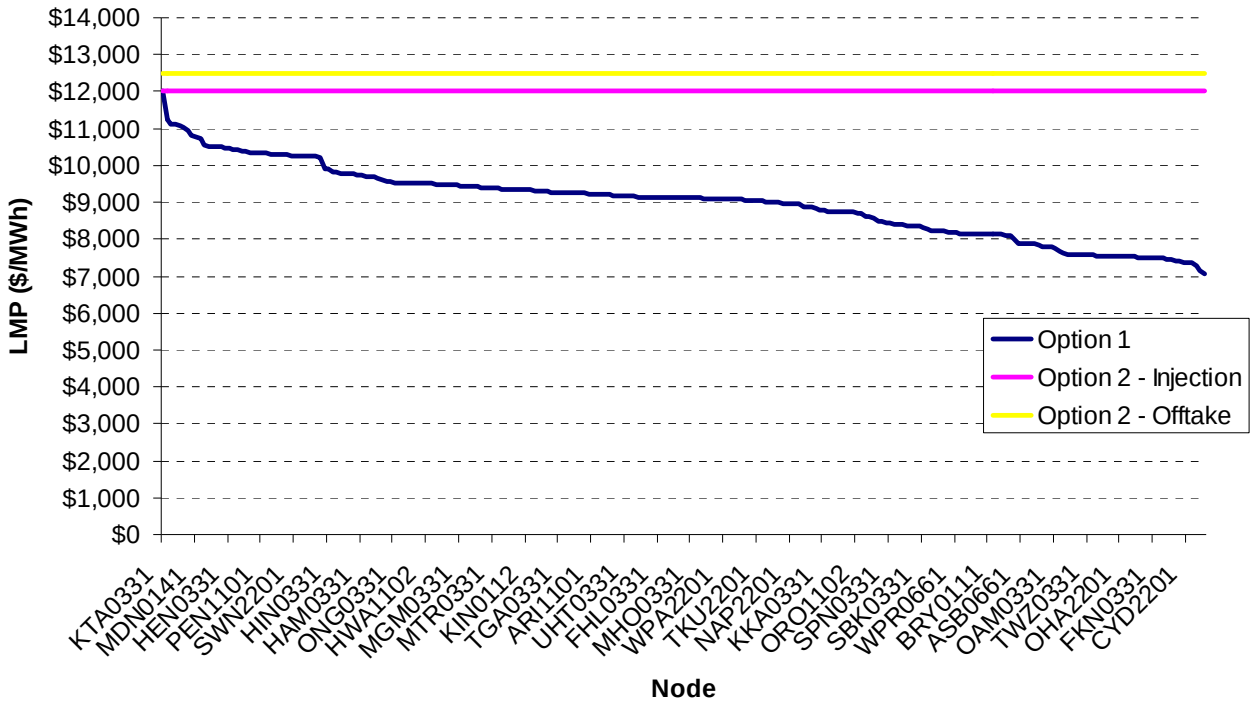
143. In either case, the cost of losses within the scarcity region would be borne by the load participants within that region. Furthermore, the two results should be equivalent, provided the chosen option is taken into account at the time the figure is set for VOLL.

144. From a practical perspective, it may be preferable to set injection prices in affected areas equal to VOLL. This should reduce (but not eliminate) the need for constrained on payments in scarcity situations.

145. The effect of adopting this option is shown below using the same illustrative situations as shown for Option 1. For ease of comparison, the nodal price pattern for Option 1 is also shown on these charts.

146. Figure 25 shows the pattern of nodal prices across New Zealand, had there been a nationwide shortage event.

Figure 25: Option 2– NZ wide curtailment event

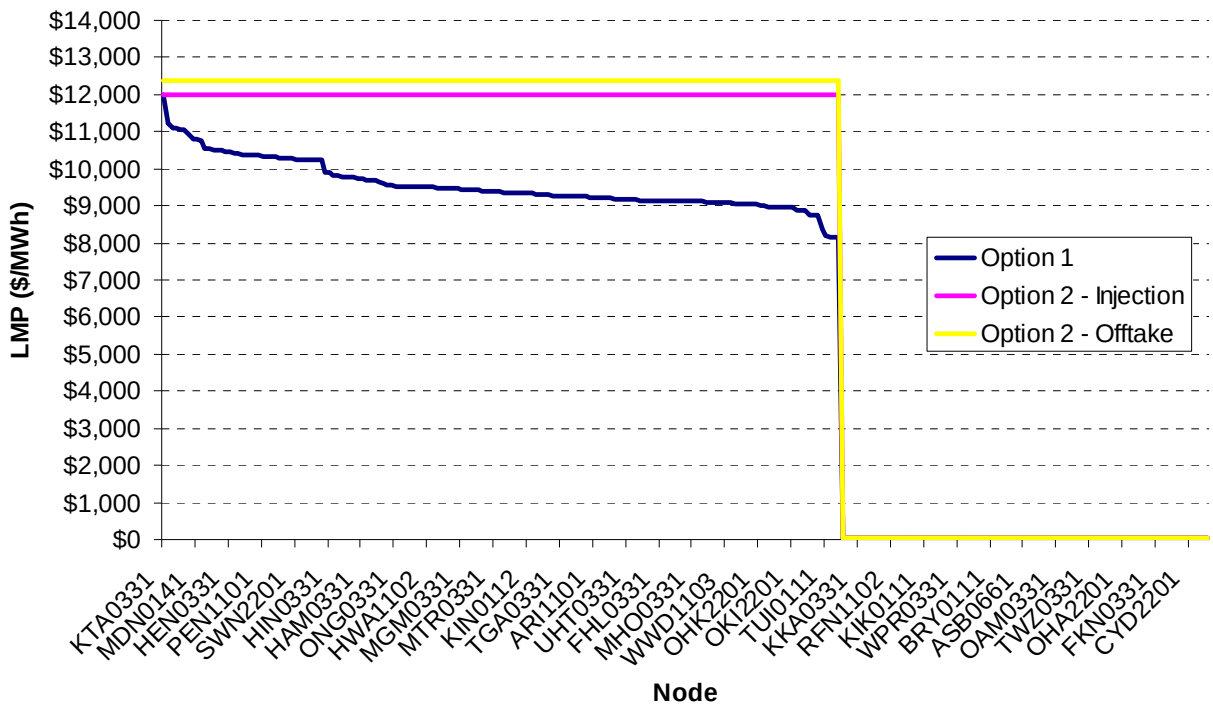


[33] A further variant of these alternatives is to allocate transmission losses to load participants based on published loss factors.

147. Prices at all injection nodes would be $12,000/MWh, and prices at all offtake nodes would be $12,473. While the difference would reflect *average* transmission losses across the entire grid in the trading period. This contrasts with the nodal pattern evident in Option 1 reflecting *marginal* transmission losses. If Option 2 were applied, it would not generate any transmission rentals in that period. This would mean that there is no settlement surplus available to fund locational price hedge instruments for that trading period, (such as for financial transmission rights or locational rental allocations).

    However, given that offtake prices would be at a uniform level across the grid, the need for such instruments in that period would be reduced. Likewise, prices at injection nodes would be at a uniform level (though lower than for offtake points). Accordingly, the only 'basis' risk that would exist would be between injection and offtake prices.

Figure 26: Option 2– North Island curtailment event

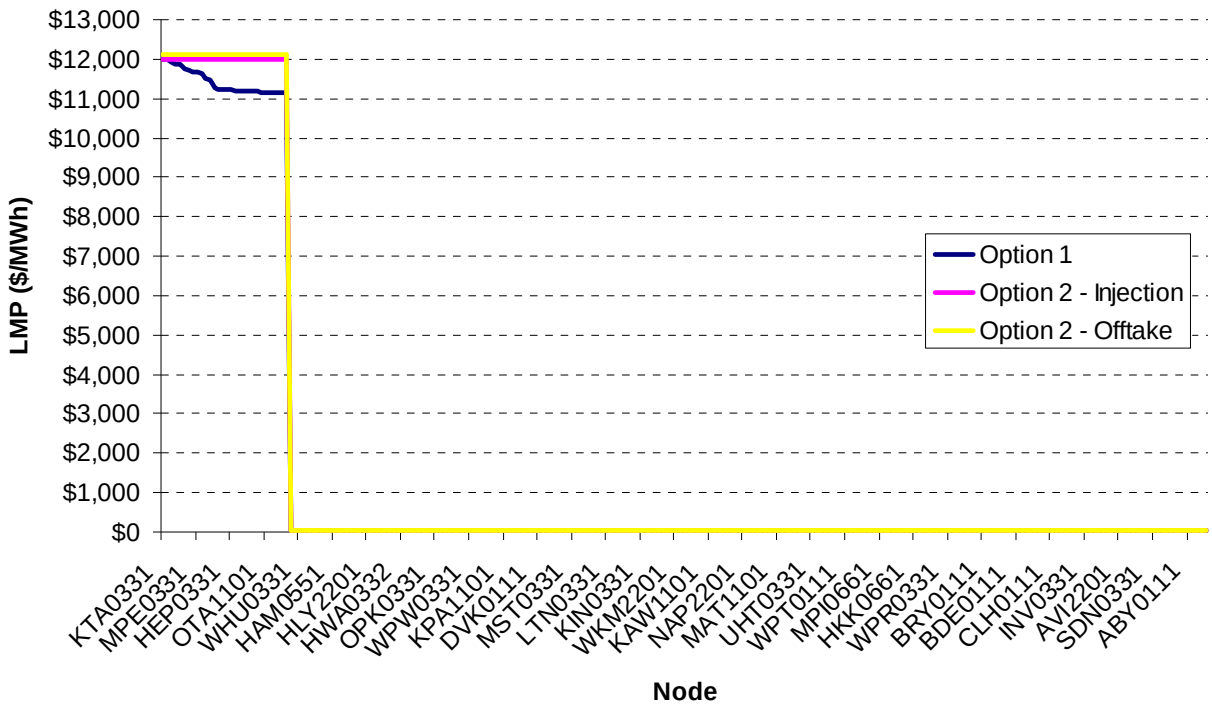


148. Figure 26 shows the pattern of prices for a curtailment event affecting the entire North Island. As with Option 1, there is a large degree of price separation with the South Island, but injection and offtake prices would be at separate uniform levels respectively across the North Island.

149. The rental pool (and hence revenue to fund locational hedge instruments) would not be adversely affected for nodes outside the scarcity region (i.e. the South Island in this example). A settlement surplus would accrue on HVDC transfers and this surplus would be available to fund any locational price risk hedging instruments that apply

across the HVDC. No settlement surplus would accrue within the North Island for intra-region price risk for the trading period. Again, however, this may be viewed as less significant given the absence of intra-island price differences for the period (other than between injection and offtake nodes).

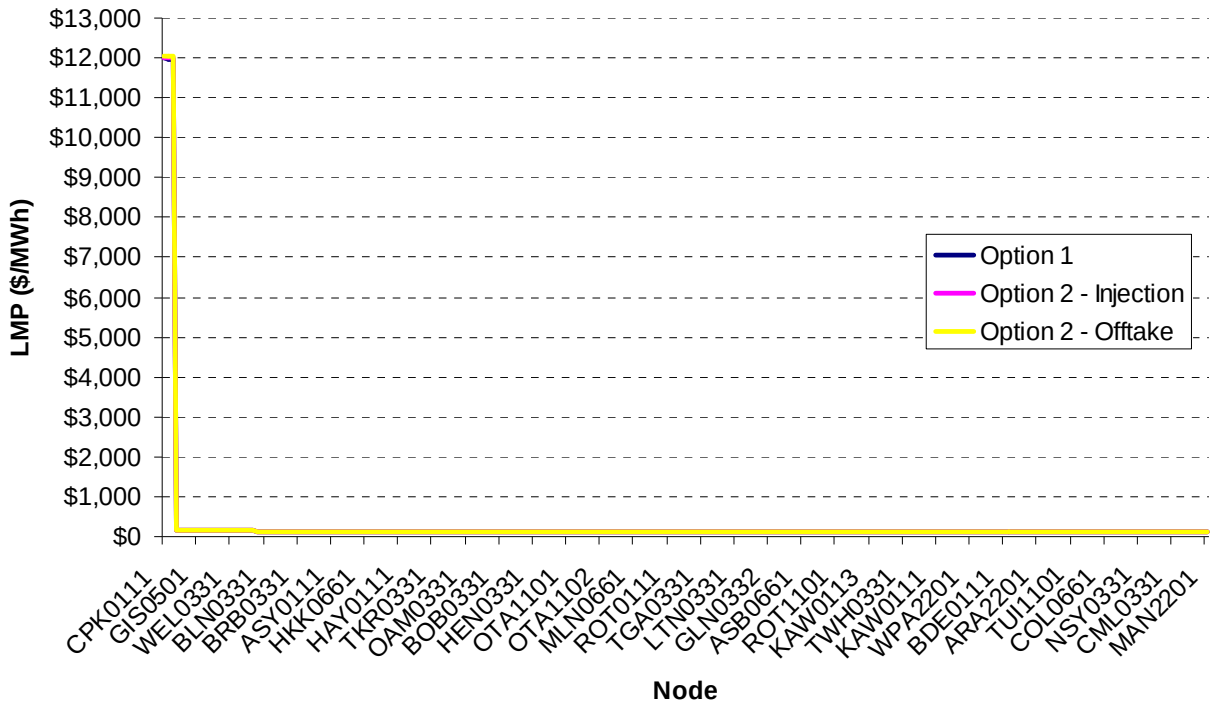
Figure 27: Option 2– Upper NI curtailment event



150. Figure 27 shows the pattern of prices for a curtailment event confined to the upper North Island. As with Option 1, there is a large degree of price separation between this region and the rest of New Zealand (creating rentals across the constrained part of the transmission grid). Unlike Option 1, prices within the upper North Island are uniform (other than the difference between injection and offtake nodes).

151. The effect on the rental pool is similar to that for the island-wide shortage. In this case, rentals generated on the grid outside the upper North Island would effectively be unchanged relative to Option 1. The settlement surplus between the scarcity region and the non-scarce region would be sufficient to fund the inter-region price risk on the constrained link. Once again, the intra-scarcity region price differences are those between injection and offtake nodes.

Figure 28: Option 2– Localised curtailment event



152. Figure 28 shows the pattern of prices for the event affecting supply into the Wilton 110kV system. The affected nodes were Wilton, Kaiwharawhara, Westwind and Central Park. In this instance, the injection price at these nodes would be set to VOLL, and an 'uplift' to reflect the impact of average losses.

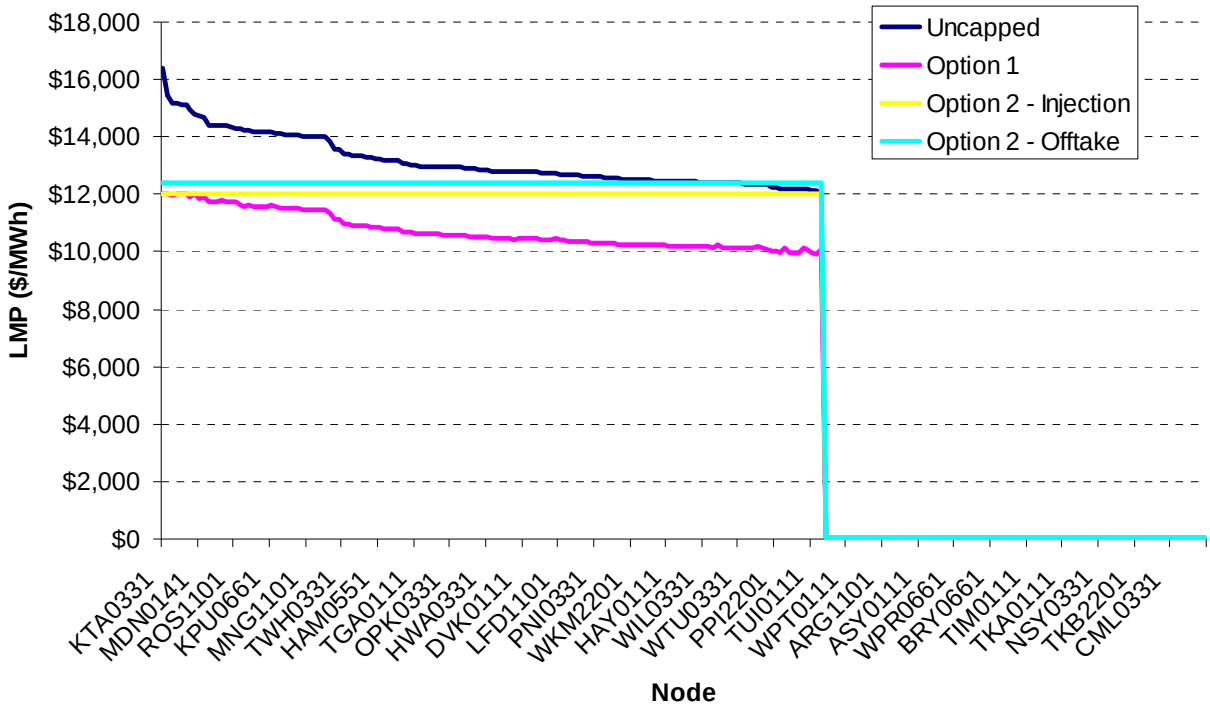
153. As with Option 1, there is a large degree of price separation between these nodes and the rest of New Zealand. The effect on transmission rentals is effectively the same under both options.

154. The discussion on Option 2 so far has focussed on how scarcity pricing would be applied. The same post processing rules can be used to introduce a form of market price cap, where grid injection node prices are capped at VOLL and grid offtake prices reflect average losses if any of the caps are 'hit'. This approach would also place a cap on offer prices at VOLL.

155. Figure 29 illustrates a situation where a central North Island generator offering at VOLL was the marginal provider for the North Iisland. In this example there are no binding transmission constraints in the system. Prices across all grid injection nodes in the North Island would be set to VOLL, and prices at offtake nodes would reflect VOLL plus the effect of average transmission losses in the North Island.

156. The resulting price pattern is similar to the shortage event illustrated earlier. The pattern is similar because from a pricing perspective, the post processing is neutral as to whether VOLL prices arise from a curtailment event or from a high offer price being dispatched.

Figure 29: Option 2– Effect of price cap for NZ



157. As compared to Option 1, this approach does not preserve nodal price differences within the group of nodes affected by scarcity or triggering of a price cap. However, it does preserve the nodal differences for other areas of the grid. A potential issue with the uplift applied to offtake nodes in Option 2 is that the capped price could be greater than the uncapped price as experienced by some nodes in the central north island in the above example.

158. Another difference is that Option 2 should not give rise to the need for constrained on payments during scarcity/market cap events. In these events, injection prices would be at VOLL. Because offer prices cannot exceed this level (due to the offer price cap), final prices should equal or exceed offer prices at each injection node.

159. As with Option 1, instantaneous reserve prices could be higher than the energy price unless they were capped. This issue will be considered further as options are defined in more detail.

Cumulative Price Threshold

160. The current thinking is that when the cumulative price threshold (CPT) is invoked, this would be achieved via a downwards adjustment to:

- the 'VOLL' offer price for Option 1; and
- the 'VOLL post-post processing price' in Option 2.

161. In both cases, the reduction of this price could increase the need for constrained-on payments, unless the offer price cap is also reduced. This appears to the approach adopted in the Australian NEM when the CPT is operating.

162. Even if a lower cap on offer prices is applied, constrained on payments could still arise under Option 1 (because final prices may be below offer prices due to marginal loss effects). Under Option 2, this potential would be reduced if load prices are scaled up to reflect average losses. However, if the CPT is applied on a nodal basis[34], it would be possible for a generator offer price (at a node not subject to the CPT) to be above the final price calculated under Option 2. Constrained on compensation could therefore still arise.

[34] This means that the cumulative price threshold would be measured and applied at each individual node.