EnergyAustralia's rule change request

Compensation provisions due to the application of an administered price, VoLL or market floor price

10 December 2007

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Appendices

1. Name and Address of Persons Making the Rule Request

This request is made under s.91(1) of the *National Electricity Law* **(NEL)** by EnergyAustralia (ABN 67 505 337 385) of 570 George Street, Sydney NSW 2000. EnergyAustralia is a corporation established under the *Energy Services Corporations Act 1995 (NSW)*.

2. Background and Role of the Compensation Provisions and Description of Proposed Rule

The arrangements for providing compensation to generators during an administered price period **(APP)** are described in clause 3.14.6 of the National Electricity Rules **(Rules)**. The core of these arrangements was included in the original version of the National Electricity Code **(NEC)**[1] prior to National Electricity Market **(NEM)** commencement. Subsequent amendments, made to reflect the introduction of an administered price floor and to allow compensation to be paid to demand-side management and market network service providers, have not changed these core principles.

During an administered price period **(APP)**, spot prices in the NEM are capped at a specified administered price cap **(APC)**. Dispatched generators with offer prices higher than the APC are eligible for compensation, to be determined by the AEMC[2] based on advice from an expert panel. Although the rationale for providing compensation is not specified in the Rules/NEC, it seems reasonable to assume that it is intended to ensure that a high-cost generator is not financially disadvantaged as a result of being dispatched when spot prices are capped.

Although the compensation requirements have not changed since NEM commencement, the process for triggering the APP has changed. Originally, an APP would commence following a "Force Majeure (FM) Event". A list of FM events was defined by the National Electricity Code Administrator **(NECA)**, and the National Electricity Market Management Company (NEMMCO) was given responsibility for identifying whether any of these events had occurred in the market and announcing the commencement of an APP accordingly.

In its 1999 review of the Value of Lost Load **(VoLL)** the reliability panel **(RP)** recognised that there were two conflicting objectives in setting the level of VoLL: to encourage new investment, particularly in peaking generation, for which a high level of VoLL was needed; and to limit financial risk for market participants, for which a lower level of VoLL was needed.

The RP proposed[3] to resolve this dilemma by introducing alternative risk management arrangements into the code which were not dependent on the level of VoLL.

[1] They were included in clause 3.16.6 of draft version 2.0 of the National Electricity Code, September 1996, as posted on the Australian Competition and Consumer Commission (ACCC) website.
[2] Or, prior to 2005, NECA.
[3] In their "Review of VoLL in the National Electricity Market", Final Report, July 1999.

"the Panel believes that [VoLL] should be raised so that market based response is assured in all parts of the NEM to facilitate voluntary clearing [and] risk exposure be **tightly controlled** in the first instance in the code" - P18 of the final report, our emphasis.

Thus, the RP proposed – and NECA and the Australian Competition and Consumer Commission **(ACCC)** agreed – to replace the FM arrangements with a "cumulative price threshold" **(CPT)** trigger, so that an APP would commence whenever the rolling weekly average spot price exceeded a specified threshold, irrespective of whether a defined FM event had occurred.

The RP recognised that it was important that the CPT/APP arrangements did not undermine the investment signalling role of the higher VoLL noting:

"a critical element of the overall proposal is that it will allow other lower cost solutions to emerge through market forces but not preclude the marginal investment in the marginal situation, should that be the most efficient outcome" – P20.

It noted that the level of the CPT might be reviewed in the future[4]. Thus, it was intended and envisaged that the CPT/APP arrangement should not hinder or distort efficient investment and, furthermore, if it was considered that it might do, the level of CPT should be reviewed. Essentially, the price signals seen in the market *prior to* the triggering of the APP would be and should be sufficient to promote efficient investment.

The compensation arrangements are not addressed in the section of the RP report that develops and justifies the proposed VoLL and CPT arrangements. However, when discussing the level of the APC, the RP notes:

"Too low a level of APC will give rise to valid claims for compensation for despatched generators with **costs** above the APC." - P21, our emphasis.

It seems that the RP did not envisage that the compensation arrangements could themselves create significant risk (and thus undermine the role of the CPT arrangements as a risk management mechanism), perhaps because the RP assumed that compensation would be based on generator direct costs rather than generator opportunity costs. As we discuss below, this assumption may be based on a flawed interpretation of the current Rules.

The RP proposals for a higher VoLL and a new CPT mechanism were accepted by NECA and the ACCC, with the exception that VoLL was restricted to $10,000/MWh, rather than the $20,000/MWh proposed by the RP. Neither NECA nor the ACCC specifically addressed the compensation arrangements, perhaps because these were essentially unchanged from the pre-existing NEC and therefore already authorised and effective.

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[4] As announced on 5 November 2007 the AEMC is conducting a consultation to review and clarify the schedule of the APC. EnergyAustralia understands that the compensation provisions are not being reviewed as part of this review by the AEMC.

In summary, EnergyAustralia believes that the RP intended that the APP/CPT arrangements cap the overall level of risk exposure in the market whilst not undermining the investment signals provided by a higher VoLL, based on an assumption that generator compensation during the APP would be based on generator direct costs.

Description of Proposed Rule

EnergyAustralia proposes that the compensation provisions currently contained in clause 3.14.6 of the Rules are amended so that:

- The requirement to take into account the difference between the spot price resulting from the administered price cap and a scheduled generator's dispatch price is removed as a consideration for assessing compensation.
- There is a clear statement that the purpose of any payment of compensation to scheduled generators is to recover direct costs incurred in respect of dispatched generating units and that the nature of direct costs is specified.
- The AMEC is required to publish the expert panel's report and its proposed determination of compensation, and invite submissions from interested parties for a period of 20 days prior to making a final determination.
- It is clear that the AEMC is required to take into account the expert panel's report, but is not bound by the panel's recommendations.

The proposed rule and how it addresses the issues which have been identified with the existing rules is discussed in further detail in Section 4.

3. Statement of Issues Concerning the Existing Rules and how the Proposed Rule will Address the Issues.

EnergyAustralia believes there are four main issues concerning the existing Rules regarding the current compensation provisions:

1. **It is unclear how the criteria for determining compensation under clause 3.14.6 might be interpreted and applied by the expert panel and the AEMC, creating uncertainty as to how much compensation will be awarded.** The Rules are not clear on how compensation is to be calculated; giving the panel and the AEMC broad discretion in determining what is a 'fair and reasonable' amount. Possible outcomes range from zero compensation to compensation for the entire difference between the capped spot price and a generator's offer price.

   The proposed rule will address this issue by removing existing references to the difference between the capped spot price and a generator's offer price and providing that the purpose of any compensation payable to a Scheduled Generator is to recover direct costs. The meaning of direct costs will be set out.

2. **Awarding compensation according to offer price may affect market behaviour and outcomes in ways not envisaged or intended by the rule designers, rendering the spot price capping ineffectual and giving rise to high levels of compensation.** Offer-price-based compensation would create an effective "pay-as-bid" market, which academic literature suggests will compensate generators at a level similar to the uncapped spot price, rendering the APP/CPT arrangements ineffective and causing compensation payments to expand to make up the difference between capped and uncapped spot prices.

   The proposed rule will address this issue by removing the reference to generator's offer price in the compensation criteria which should limit the possibility or expectation of a "pay as bid market".

3. **Unlike normal spot market payments, the compensation payments under clause 3.15.10 are not able to be hedged, creating major risk and uncertainty for retailers and their customers.** A prudent retailer will have limited exposure to high spot prices, having entered into hedge contracts with generators, but is not likely to be able to arrange similar hedging against high compensation payments. Thus, the effect of the APP/CPT arrangements – particularly if pay-as-bid ensues – may simply be to turn hedged high spot prices into unhedged high spot prices, with consequential adverse impact on retailers and their customers.

   The proposed rule will address this by reducing the risk of high levels of administered price cap compensation and thereby reducing the risks which arise from being unable to hedge against high compensation payments.

4. **The process for determining compensation lacks transparency and does not clearly delineate the roles of the AEMC and the expert panel.** There is no opportunity for interested parties to be involved in the panel's deliberations or to be consulted before the AEMC makes a determination.

   The proposed rule will address this by requiring the AEMC to publish the expert panel's report and the AEMC's proposed determination on compensation and invite submission in relation to those matters during a 20 day consultation period. The AEMC will be required to taken into account the panel's recommendation and submissions but will not be bound by the panel's recommendations.

The above issues are elaborated further below.

3.1 Uncertainty in the determination of compensation

The compensation provisions in clause 3.14.6 of the Rules create the potential for a range of compensation outcomes, from no compensation to the generator's bid price, but contain no clear guidance or criteria on when and how much compensation should be paid.

There are five key elements established in the compensation arrangements for scheduled generators in 3.14.6 of the Rules:

1. Only dispatched generators whose offer price is higher than the APC may claim compensation (3.14.6(a));
2. The AEMC must determine whether it is appropriate in all the circumstances for compensation to be payable and the amount of the compensation (3.14.6(c));
3. Before making a determination, an expert panel must be established to make recommendations on the matters to be determined by the AEMC (3.14.6(c)(d));
4. The expert panel must base its recommendations on its assessment of a fair and reasonable amount of compensation taking into account:
   - All the surrounding circumstances;
   - The actions of any relevant Registered Participants and NEMMCO; and
   - In the case of a claim by a Scheduled Generator, the difference between the capped spot price and the generator's offer price (3.14.6(e)(3)).
5. The AEMC would be bound to consider the expert panel's report when determining whether compensation is payable.

The panel must address itself and its recommendations to the matters to be determined by the AEMC; whether it is appropriate for compensation to be paid and the appropriate amount.

Firstly, the panel must consider whether it is appropriate in all the circumstances for compensation to be payable by NEMMCO. The Rules provide no specific guidance on the threshold question as to whether compensation should or should not be paid other than whether it is "appropriate", 3.14.6(c). The matters to be taken into account under 3.14.6(e) appear to go only to an assessment of a fair and reasonable amount of compensation not to the threshold question of whether compensation is payable. This creates uncertainty and is likely to lead to a presumption in favour of determining some level of compensation by bundling up the two issues and addressing the issue of the "fair and reasonable amount of compensation" rather than the threshold issue of whether compensation should be payable.

If the panel did address itself to the threshold question, it could be faced with competing arguments and may find it difficult to refuse to recommend some level of compensation. On the one hand it could take the view that no compensation should be payable if the generator voluntarily bid into the market knowing that a capped spot price applied. However this would be countered with the argument that such a bid would have been made knowing that compensation provisions were in place. The panel might consider the level of financial impact and take the view that if that level was small compensation was not appropriate, this could be countered with an argument that the quantum of the claim should not bear on the appropriateness of compensation. Ultimately the panel would be under pressure to consider some level of compensation because the rule provides no clear basis for when compensation should and should not be payable.

Secondly, the panel must make an assessment of what is intended by the "fair and reasonable" requirement. In determining what is fair and reasonable, the panel must take into account all the surrounding circumstances, the actions of any relevant Registered Participants and NEMMCO and the difference between the offer price and the capped spot price. Whilst these provisions do not guarantee compensation at the bid price, they do not preclude it and moreover provide no guidance on an alternative basis for compensation. Typically, in other contexts "fair and reasonable" is interpreted to mean a value which is acceptable to both buyer and seller, in the sense that it is no lower than the minimum that the seller will accept and no higher than the maximum the buyer is prepared to pay[5]. The minimum that a generator will accept would be its direct generating costs. The maximum that a consumer is prepared to pay is VoLL. So any compensation value which ensures that the aggregate payment to a generator is between its avoidable costs and VoLL may be considered to be "fair and reasonable".

Simplistically, it could be argued that the financial impact on the generator is the difference between the level of the uncapped spot price and the APC, since this determines the generator's loss of revenue. However, the panel is unlikely to recommend this level of compensation, as this would explicitly negate the effect of the price capping, by restoring aggregate generator payments to the level of the uncapped spot price. Nevertheless, the panel may feel bound to determine compensation at a level more towards the bid price than the generator's direct costs because of the requirement to take into account the difference between the capped spot price and the generator's bid price. On this basis, the panel may decide that any level of compensation less than the offer price is not fair and reasonable, as it would result in the generator not being fully "compensated" for the application of the APC.

3.2 Economic effects of offer-price-based compensation

In the event that compensation under clause 3.14.6 is based on the difference between offer price and the capped spot price, the aggregate payment to dispatched generators[6] (including payment at the capped spot price under clause 3.15.16) will be equal to its dispatched output multiplied by its offer price. This form of compensation is often referred to as "pay-as-bid", in contrast to the more common regime (and the one on which the NEM is based) of all generators being paid a common clearing price irrespective of their offer price.

[5] For example, in relation to proposed corporate takeovers.

[6] Much of the discussion in this section would also apply, mutatis mutandis, to market network service providers and demand-side bidders. However, given the relatively small size of these sectors, the materiality of the impacts will be much lower. For this reason, our focus is on the generation sector.

The impact of such a pay-as-bid regime is likely to be that:

- The APP mechanism becomes ineffective, as generator payments in aggregate from the spot market will be similar to what they would have been at the uncapped spot price;
- Given the high level of uncapped spot prices that is likely during an APP, this means that compensation payments may be very large; and
- Dispatch may become inefficient, disorderly or insecure.

The starting point for understanding why such impacts may arise is to consider how the transition from a conventional spot pricing regime to a pay-as-bid regime will affect each generator's bidding strategy. Under conventional spot pricing, economic theory suggests that competition will drive generators to reveal their variable costs. However, under pay-as-bid, this theory no longer applies and different competitive pressures apply.

The American economist, Peter Crampton noted[7] that:

> "With pay-as-bid pricing, the bidder's incentive is to bid as close to the clearing price as possible. Indeed, the pay-as-bid auction may be renamed "Guess the Clearing Price." The pay-as-bid auction rewards those that can best guess the clearing price."

In 2001, the California Power Exchange appointed a "Blue Ribbon" Panel of eminent economists[8] to predict price and dispatch outcomes in a pay-as-bid market and compare these with conventional spot price clearing. The panel noted:

> "The critical assumption [for those arguing that pay-as-bid would lower generator payments] is, of course, that after the market rules are changed [to pay-as-bid] generators will bid just as they had before. *The one absolute certainty, however, is that they will not.* Knowing that unless they changed their bidding practice under the new system they would receive only their avoidable costs on their successful bids—yielding them no contribution to their fixed or common costs, let alone profits—they obviously will universally change their practice immediately, bidding instead at what they *expect* will turn out to be the market-clearing price".
>
> "To the extent that the several bidders were able perfectly to predict the market-clearing price, in short, the savings from the change in the rules [from spot pricing to pay-as-bid] for consumers would prove to be zero. The only difference between the average prices actually realized under the two systems would, therefore, be the extent—and only the extent—to which their predictions proved to be mistaken" – P5 of the report.

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[7] In "Electricity market Design: the Good, the Bad and the Ugly", published in the proceedings of the Hawaii International Conference on System Sciences, January 2003.

[8] See "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing"; Alfred Kahn, Peter Crampton, Robert Porter, Richard Tabors, January 2001.

This might appear simply to make the price-capping provisions under the APP ineffective, but it is in fact worse than this.

Firstly, the generation merit order (i.e. the ranking of generators by offer price) will reflect not generator costs but the various guesses that each generator makes about the future clearing price. It is quite possible that a high cost generator may guess a lower price – and so bid lower - than a low cost generator and so the high cost generator will be dispatched first, leading to higher dispatch costs and lower dispatch efficiency.

Secondly, the "guess the clearing price" strategy will necessitate substantial rebidding as expectations of the clearing price change. This is likely to disrupt the dispatch process and, at a time when the market is already under severe stress, may jeopardise system security or reliability. Incidentally, the rebidding rules in the NER would not, in EnergyAustralia's view, prohibit such rebidding, so long as the genuine reasons for such rebidding are properly declared[9].

It is quite possible that the designers of the compensation arrangements did not contemplate the consequences of pay-as-bid[10] and assumed, perhaps naively, that, offer prices would be a reasonable reflection of – and a convenient proxy for - direct generating costs, as might be expected under a conventional spot pricing regime. In this respect, the rule change proposal set out in section 4 of this submission goes some way to restoring these original objectives for the compensation arrangements.

3.3 Impact of unhedgeable compensation costs on retailers and their customers

3.3.1 Compensation costs are unhedgeable

Under clause 3.15.10, compensation paid to generators under clause 3.14.6 is recovered from retailers in proportion to their market share. These compensation payments by retailers, therefore, are an uncertain proportion of the aggregate compensation payment to a number of generators. Since no individual generator can estimate in advance what proportion – if any – of the aggregate compensation it will receive, it is not in a position to offer hedge contracts to retailers that would insure a proportion of the aggregate amount. Furthermore, given the uncertainty over how compensation amounts will be determined, it is highly unlikely that other organisations, such as commercial insurers, would offer hedging contracts.

To all intents and purposes, therefore, these compensation payments are unhedgeable, meaning that their full financial impact will fall on retailers and/or their customers. The consequences of large, uncertain and unhedgeable costs being imposed on retailers are discussed in the following sections.

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9 Clause 3.8.22 of the Rules provide that a generator may vary its bids, subject to providing to NEMMCO a "brief, verifiable and specific reason for the rebid" and "the time at which the event adduced by the generator as the reason for the rebid occurred". Under a guess-the-clearing-price strategy the reason would be that the generator's forecast of the clearing price had changed, for example in the light of a new pre-dispatch run.

10 Remembering that these rules were drafted in 1996, prior to NEM commencement and well before the publication of the academic literature quoted above.

3.3.2 *Maintaining risk capital*

A prudent retailer will maintain a portfolio of hedging contracts so as to limit its overall exposure to volatility in the spot market. It will also hold "risk capital" to cover any residual exposure (i.e. capital that can easily and quickly be accessed and liquidated in the event that additional funds are required for settlements in extreme market conditions). To avoid, or substantially reduce, the risk of insolvency, a retailer must hold a level of risk capital equal to the financial impact of a "worst-case scenario": a credible market event or sequence of events with maximum financial impact.

Presently, the worst-case scenario for EnergyAustralia – and we would expect for all prudent retailers – is the prospect of a triggering of the CPT and the resulting unhedgeable pay-at-bid market discussed above. As set out in Appendix 1, the financial impact of this could be orders of magnitude worse than any impacts that might arise during periods of normal market clearing.

Until recently, the likelihood of a triggering of the CPT has appeared remote[11]. However, with significant generating capacity currently being affected by the drought conditions – and in the light of prices seen in winter 2007 when the CPT came close to being triggered – EnergyAustralia believes that there is a material probability of an APP being triggered this summer.

Risk capital must be paid for, of course, and given that all retailers will be similarly exposed to APP compensation[12], the associated costs are likely to be passed through to customers (to the extent that any regulated retail price caps allow this) in higher retail margins. Indeed, given the level of risk capital required, it may be that many retailers – particularly those without access to a large parent company balance sheet – are simply unable to economically procure this capital. They must then either exit the market, or be at risk of insolvency should the worst-case scenario arise[13].

3.3.3 *Pass-through to customers*

An alternative to maintaining this risk capital is to have arrangements to "pass-through" or "clawback" from customers the extra costs of APP compensation.

It is highly unlikely that even the largest and most well-informed customers would be prepared for such an event. Even customers that were aware of the relevant "pass-through" provision in their supply contracts would be unlikely to anticipate the magnitude of this clawback in the event of APP compensation. As a result, any clawback is likely to cause substantial disruption, distress and hardship for customers, particularly residential customers.

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[11] In a report to the ACCC on the CPT mechanism, IES concluded that "The level of generator capacity that must be lost for price risk to reach CPT levels is substantial. The studies suggest that 1500 MW to 2000 MW of base-load generator capacity would need to be lost [for the CPT to be triggered]", P ii, "Modelling the Impact of VoLL and CPT in the NEM, A report to the ACCC", October 2000 ("IES report to ACCC").

[12] The compensation risks cannot be hedged by retailers, at least not conventionally.

[13] In fact, if capital markets are efficient, this latter route would not in any case save them the cost of risk capital. The cost would instead be seen in the higher cost of capital demanded by shareholders and creditors in the light of the higher insolvency risk.

The clawback process would also be costly for retailers, requiring special billing arrangements and customer communications. Furthermore, given that there would be some time before the clawback monies would be received, there would still be a need for retailers to access substantial working capital to avoid insolvency in the intervening period. This may also be costly and cause financial difficulties for the majority of retailers given the 15 day settlement period for payment of compensation under clause 3.15.10.

Pass-through of these costs to customers on regulated tariffs would be subject to regulatory approval and so, if allowed at all, would be subject to considerable delay.

3.3.4 Retailer insolvency

Retailers that did not hold risk capital and did not have pass-through arrangements would likely become insolvent as a result of APP pay-as-bid. If a substantial part of the retail market became insolvent, this may have secondary impacts on contract counterparties of insolvent retailers, leading to the sort of "systemic risk" that the APP arrangements are designed to avoid.

Whilst the "retailer of last resort" arrangements are designed to protect customers in the event of retailer insolvency, there will undoubtedly be some additional costs flowing to customers in this scenario. More significantly, the insolvencies will damage the perception and reputation of the energy retail sector, leading to higher costs of capital for existing retailers and a significant new entry barrier for new retailers. The insolvencies may also trigger new government or regulatory intervention which, while endeavouring to protect customers, may further damage the competitiveness and efficiency of the retail sector.

3.3.5 Summary

The existing compensation arrangements are likely to adversely affect the retail market by:

- Creating the possibility or probability of very large, unhedgeable compensation amounts being borne by retailers following an APP;
- Requiring prudent retailers to hold large amounts of risk capital to ensure their continued solvency, the cost of which is likely to be passed on to customers;
- Alternatively, requiring prudent retailers to make arrangements to clawback the compensation cost from their customers, causing major customer disruption and hardship; and
- Alternatively, causing insolvency for retailers who are not adequately prepared for the APP aftermath, which will lead in the short term to customer disruption and possible systemic credit risk and, in the longer term, to a less efficient and competitive retail sector.

3.4 Lack of Transparency

Neither the expert panel nor the AEMC is expressly required to consult with affected participants in the determination of compensation. This is in contrast to other areas of the Rules (i.e. clauses 3.12.11A and 3.15.7A) where compensation amounts are based on recommendations by independent experts and where consultation on these recommendations is required.

This lack of transparency further exacerbates the risks associated with APP compensation, given the inability of retailers – in particular – to challenge the assumptions or methodology on which the compensation amounts are determined.

4. Description of the Proposed Rule Change and how it Addresses the Issues

4.1 Description of proposed rule change

The proposed rule changes the criteria and process for determining APP compensation in a number of ways. However, it retains the role of the AEMC as the body responsible for determining compensation and an expert panel to make recommendations to the AEMC.

Firstly, the proposed rule replaces the requirement to take into account offer prices with the requirement to take into account that the purpose of compensation is to enable the recovery of direct generating costs. A description of these costs has been drawn from existing provisions in clause 3.12.11(d), although alternative definitions might also be appropriate[14]. The key principle is that compensation is **based on cost**, not prices, so that the exposure to changing generator bidding strategies discussed in section 3 is removed. This change only applies to generators and not to Market Network Service Providers **(MNSPs)** or demand-side bidders, because:

- The MSNP and demand-side bidder sectors are relatively small and so the materiality of compensation uncertainty is commensurately lower; and
- Determination of MNSP and demand-side bidder direct costs may be more complex than determination of generator direct costs.

However, EnergyAustralia would not object to extending the change to MNSPs and demand-side bidders if this were found to be appropriate.

Secondly, the proposed rule clarifies the roles of the AEMC and the expert panel, and the factors that must be taken into account, in relation to both the threshold question of whether compensation is to be awarded and the determination of a fair and reasonable amount.

Finally, the proposed rule introduces a consultation process, whereby the AEMC must publish and receive submissions on a draft expert panel report and take these submissions into account in its determination. This will make explicit an obligation (which would most likely be implied) that the

[14] Direct generating costs are also defined, somewhat differently, in 3.15.7B(a3), for example.

AEMC provide an opportunity for persons affected by a decision to be made aware of the proposed decision and to provide comments on the likely impact of the decision before that decision is made.

The proposed rule will require amendment to subclauses 3.14.6(c) and (e) and the inclusion of new subclauses (f) and (g). A suggested draft of the proposed rule is at Appendix 2.

4.2 How the proposed rule addresses the issues

The proposed rule removes much of the uncertainty over the criteria for determining compensation, by making it clear that the objective of the compensation is to ensure that a dispatched generator is able to recover its direct generating costs during an APP. It also better delineates between the two tasks of deciding on whether compensation should be awarded and determining the compensation amount.

By removing reference to offer prices in relation to generator compensation, the proposed rule substantially removes the possibility or risk that a pay-as-bid market may be created, or be perceived to be created, during an APP. Whilst it is still conceivable that the panel/AEMC may take account of offer prices in determining compensation, such a remote possibility is unlikely to prompt the guess-the-clearing-price bidding strategies discussed in section 3, with their attendant problems.

The proposed rule does not facilitate – and is not intended to facilitate – hedging of retailer compensation payments. However, by substantially reducing the risk of high levels of APP compensation, concerns associated with this issue are also substantially reduced. Estimates of the magnitude of compensation payments and retailer risks under the current and proposed rules, described in Appendix 1, suggests that concerns about retailer and customer impacts are substantially addressed under the proposed rule.

Finally, the proposed rule addresses the transparency concerns by requiring the AEMC to consult with stakeholders on the expert panel report. The proposed approach is that the consultation is undertaken by AEMC – rather than by the expert panel – because the AEMC has the ultimate decision on the level of compensation to be awarded.

4.3 Economic effect of proposed rule

4.3.1 Overview

As discussed above, the purpose of the proposed rule change is to ensure that compensation to generators during an APP is based on their direct generating costs, rather than on their offer prices.

As noted above, there may have been an underlying expectation of those that have considered the Rules to date (the RP, NECA and the ACCC) that this would be the outcome of the current arrangements, given that offer prices are generally assumed to broadly reflect generator costs. In this respect, the proposed rule change simply ensures that the drafting of the Rules is amended to better achieve the original intention and expectation of the NEM designers.

In practice, as EnergyAustralia discussed above, we believe that the current Rules may lead to generators being compensated not at cost, but at levels close to the uncapped spot price. Therefore, the Rule change proposal is substantive and, as we argue below, will deliver substantial economic benefits, in accordance with the NEM objective. Specifically:

- The adverse impacts on the retail market of the potential, currently, for extreme levels of APP compensation are entirely mitigated;
- The adverse impacts on dispatch efficiency of guess-the-clearing-price bidding strategies are also entirely mitigated; and
- There is likely to be no material effect – positive or adverse – on generation investment or on generation availability during the APP.

These conclusions are discussed and explained in the following sections.

4.3.2 Reduction of retailer and customer risks

As we demonstrate in Appendix 1, with APP compensation based on generator costs, retailer risks associated with APP compensation are substantially reduced. That is not to say that retailer risk is removed entirely – nor should it be. Retailers still face material risk, both in the pre-APP period[15] and during the APP, where prices can still be at the APC. However, these risks can largely be managed by a prudent retailer maintaining a suitable hedging portfolio.

With the APP risks limited, the adverse consequences of APP compensation discussed above (i.e. costs of maintaining risk capital, impact on customers of a clawback, costs and impacts of retailer insolvency) are largely mitigated[16].

In mitigating retailer risk during the APP, the proposed rules achieve the RP's original intentions in introducing the CPT trigger: that VoLL risks are "tightly controlled".

4.3.3 Preservation of orderly generation market during an administered price period

The proposed rule change explicitly rules out any possibility of a de facto pay-as-bid market occurring during the APP, since compensation would no longer be based on offer price. The adverse effects of "guess the clearing price" generator bidding strategies on dispatch efficiency and security will therefore no longer eventuate, since generators will have no reason to adopt such strategies. While generators may still need to adapt their bidding strategies somewhat during the APP, the prospect of major disruptions to the generation merit order described above is largely removed.

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[15] Where prices must be very high so as to trigger the APP and may in fact be fairly high for an extended period without triggering the APP.

[16] Appendix 1 demonstrates that, although the risks arising from compensation to generators may still be substantial, they will not be at the extreme level that may be seen in the current arrangements.

4.3.4 Preservation of generation investment signals

An argument that might be raised by others against the rule change proposal is that, by limiting any generator upside during an APP, it dampens the signals for generation investment and so may have the longer-run consequence of lower capacity margins and poorer supply reliability.

EnergyAustralia does not think that these concerns are valid, for a number of reasons. Firstly, the CPT trigger was designed to ensure that investment signals were preserved. This is done by allowing generators plenty of upside from extreme market circumstances prior to the commencement of the APP. Quoting again from the RP report on VoLL:

> "It is therefore critical that the level of the CPT does not override the incentive that the level of VoLL is intended to deliver." (P19).
>
> "Depending on the level of VoLL, the CPT can be set more conservatively in the first instance and reviewed annually along with the value of VoLL and, if appropriate, progressively relaxed. " (P19).
>
> "The CPT of 300,000 [subsequently revised down by the ACCC to 150,000] will allow a marginal supply side investment with a capital cost of approximately $400/kW to earn up to 3 times [revised down to 1.5 times] its annual capital requirement of $50,000/MW/yr before the administered price is applied", (P20).

In the event that the market disturbance has been taking place for a longer period than this – albeit without creating price levels sufficient to trigger the CPT – earnings may be much higher than this. For example, a peaking generator in NSW could have earned around $80/kW contribution towards its fixed costs last winter, although price levels were insufficient to trigger the CPT.

Indeed, given that the level of the CPT is currently under review[17], if the AEMC considers that the pre-APP earnings are insufficient to signal efficient generation investment, it has an obvious remedy in raising the level of the CPT, rather than continuing to allow additional upside during the APP itself.

Secondly, the long-term frequency of APPs is likely to be very low[18], so that prospective earnings during an APP are unlikely to materially affect investment decisions. (Although we have argued above that, in the short-term, the probability of an APP is quite high, this is in the context of the ongoing one-in-a-hundred-year drought). Even if a generation investor *did* take account of this

[17] The Reliability Panel is due to report its findings on the level of CPT later this year, as part of the comprehensive review of reliability.

[18] IES found, in their report to the ACCC that "under normal market conditions of generator breakdowns and high demands, market risk would not be expected to reach the levels at which CPT would operate" and that "market risk would not be expected to reach the levels at which CPT would operate even under the loss of significant [1000MW] generation.

APP revenue, they would be likely to prudently assume the lowest likely level of APP compensation: i.e. something based on generator costs[19].

Finally, a prudent generator will largely hedge its spot price exposure by selling hedging contracts. For example, a peaking generator will sell cap contracts, under which it is guaranteed to receive the fees from sales of these contracts, irrespective of spot price outcomes. In a balanced generation market, these fees should be sufficient to cover a peaking generator's fixed costs and so will ensure that these costs continue to be covered in the lead up to and during an APP.

Investment, then, will be driven largely by the anticipated future price of hedging contracts, not by anticipated payments in the spot market. Because APP compensation payments are not hedged by these contracts, changes to the compensation methodology will not affect the contract value or contract price and so will not affect investment by prudent generators.

4.3.5 Preservation of generation availability during an administered price period

Another possible concern that may be raised (by others) is that restricting compensation to generation costs may discourage generators from making capacity available during an APP: capacity that is likely to be badly needed.

EnergyAustralia does not share this concern, for a number of reasons. Firstly, a generator is reasonably guaranteed[20] to recover its costs during an APP, so will not be "out of pocket" as a result of making itself available. This is particularly important where a generator incurs substantial costs in becoming available: for example by cancelling a planned outage or having to use an alternate fuel such as distillate.

Secondly, generators are likely to use their best endeavours to make themselves available during an APP for the good of the market as a whole and to limit the prospect of any damaging publicity – perhaps even allocation of blame for any load shedding – as a result of not being available when needed. They will not need substantial financial incentives to do this.

Finally, NEMMCO has the power to direct a generator to make itself available in the event that its capacity is needed to avoid load shedding. Although it is always preferable that such NEMMCO intervention is kept to a minimum, the presence of this safety net will limit the ability of a generator to withdraw its capacity from the market during an APP.

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[19] In contrast to a prudent retailer who, as discussed above, must assume the *highest* likely level of APP compensation.

[20] It may not recover its costs if it is not dispatched, but since load is likely to be shed at some point during an APP, it is almost certain to be dispatched.

4.3.6 Consistency with compensation for directions

The rules, under clause 3.15.7A, also provide compensation for generators in the event that they are directed. Unlike the proposed rule change for APP compensation, directions compensation is based on an estimate of a "market price" for the directed service[21].

A possible concern that may be raised (by others) is a putative inconsistency between APP compensation in the proposed rule change and the directions compensation. However, EnergyAustralia does not agree with this concern. The different approaches reflect the different circumstances in which compensation is awarded and the different objectives of the two arrangements.

As discussed earlier, the intent of the CPT/APP arrangements is to ensure that market risk is capped during extreme market events. This is done by ensuring that risk is tightly managed during an APP, through the price capping process. In contrast, the intent of the directions arrangements is to ensure that a generator is adequately compensated for any services which are required by the market and which are not fully compensated under the normal market rules. In this context, the generator must be compensated at a market rate to ensure that it is able and available to provide that service in the future if it is needed. Simply compensating a generator at cost may be insufficient to ensure this.

4.3.7 Summary

The economic effects of the proposed rule change will be:

- To remove any possibility of a pay-as-bid market during an APP and of the related adverse impacts on the wholesale market;
- To remove any possibility of large, unhedgeable compensation costs being passed onto retailers and of the related adverse impacts on the retail market and customers;
- To preserve the existing signals for efficient generation investment; and
- To preserve sufficient incentives for generators to make capacity available as needed during an APP.

5. How the Proposed Rule Change Will or is Likely to Contribute to the Achievement of the NEM Objective

The National Electricity Market objective is:

> "to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system".

[21] Clause 3.15.7A(c)(1)(ii)(d).

Section 4 explains the economic effect of the proposed rule and addresses in detail the positive effect of the proposed rule on:

- The provision of generation to the market (see section 4.3.3 and 4.3.5);
- Generation investment signals (see section 4.3.4);
- The provision of retail services (see section 4.3.2); and
- The interests of consumers (see section 4.3.2.).

Specifically, the proposed rule change will or is likely to contribute to the achievement of the national electricity objective in the following ways:

- Promote efficient investment in electricity generation by preserving the existing signals in the NEM which are established through the level of VoLL and the CPT/APP arrangements;
- Promote efficient use of electricity generation capacity by ensuring efficient and secure dispatch during an APP, by removing the possibility of a pay-as-bid market;
- Promote efficient investment in retail services by removing the possibility of extreme, unhedgeable compensation recovery charges being levied on retailers in the aftermath of an APP and so reducing the level of retail risk and so the retailer cost of capital;
- Promote efficient retail prices by reducing the amount of risk capital that a retailer must hold to maintain solvency during a worst-case scenario (for exampe the triggering of an APP);
- Promote the long-term interests of consumers by removing the possibility of major customer disruption and hardship in the aftermath of an APP which would result from retailers passing through the compensation costs to customers or from retailer insolvency; and
- Ensure that the existing levels of reliability and security of electricity supply and the national electricity system are maintained by preserving the incentives for efficient generation investment and for generators to make generation capacity available for dispatch during an APP.

6. Power to Make the Rule

The proposed rule change is a rule generally with respect to the operation of the NEM and specifically with respect to setting of pricing for electricity and services purchased through the wholesale exchange operated and administered by NEMMCO, including the maximum and minimum price. Consequently the AEMC has the power to make the proposed rule under s 34 of the NEL.

Signed for on behalf of EnergyAustralia by:

Mike Bailey
Executive General Manager Retail

Appendix 1: Estimates of Materiality of Cumulative Price Threshold and Compensation Alternatives for EnergyAustralia

Estimates of Materiality of Cumulative Price Threshold and Compensation Alternatives for EnergyAustralia

Methodology

In the main text, EnergyAustralia argues that the existing compensation arrangements may have the effect of creating a pay-as-bid market during price-capped periods, meaning that aggregate payments to generators would, in a worst-case scenario, be similar to the payments that would be made at the uncapped spot price.

Under the pay-as-bid assumption, the compensation payment will be similar to the difference between the capped and uncapped spot price. Since the APC is $100/MWh during peak periods (and extreme prices are unlikely during off-peak periods), the compensation payment for each MW of demand will be similar to the difference payments due under a 1MW cap contract with a strike price of $100/MWh.

In its report to the ACCC, IES estimated that the aggregate value of these difference payments – which it referred to as the "risk premium" - under a range of market scenarios[22]. To derive the estimates in this appendix, we have used the IES scenario under which:

- VoLL is $10,000/MWh and CPT is $150,000 (the current values of these parameters);
- There is a loss of 2000MW of generating capacity (the only generation scenario that triggered the CPT); and
- The level of demand management in the market is "medium" (IES considered "high", "medium" and "low" DM scenarios, so we have adopted the middle ground).

IES estimated that, without a CPT (i.e. with no price capping) the risk premium for this scenario would be $608,469/MW[23], or $608/kW[24], and with a CPT (i.e. with price capping) the risk premium would be $302/kW. So the difference between the capped and uncapped prices is approximately $300/kW. Whilst the analysis was carried out several years ago, using a range of assumptions which may or may not be entirely valid today, EnergyAustralia thinks it is reasonable to use this result as an indicative estimate of the impact of price capping during an APP, recognising that –

[22] P6 of the IES report. In fact, IES assumed a strike price of $300/MWh, so the risk premia estimated in their report will represent a value somewhat less than the difference between the capped and uncapped spot prices. For example, during the winter (Jun-Aug inclusive) of 2007, the risk premium in NSW at a strike price of $100/MWh was around 50% higher than at a $300/MWh strike price. Therefore, using the IES results is a conservative approach.

[23] P24 of the IES report. In its report, IES expressed the risk premium in units of $/MWh, which is the contribution of the overall risk premium to the average annual spot price. To convert from $/MWh into $/MW, one just needs to multiply by 8760 (hours in a year). So the $69.46/MWh of risk premium estimated by IES becomes 69.46*8760 = $608,469/MW. Expressed in $/MW, the premium represents the dollar contribution from spot prices towards a peaking generator's fixed costs for each MW of capacity.

[24] EnergyAustralia use units of $/kW in this report, because the numbers are more manageable and because they relate more directly to the impact on retail customers.

due to the extreme volatility of prices during an APP and the range of scenarios in which the CPT might be triggered – any modelling will at best give a ball-park estimate.

The $300/kW premium estimated by IES might be generated by, say an average uncapped spot price of $1100/MWh (i.e. a premium of $1000/MWh over the capped spot price), for 300 hours, or prices at VoLL (a premium of $9,900/MWh) for approximately 30 hours, since both create the same risk premium: i.e.

$1000/MWh * 300 hours = $300,000/MW = $300/kW; or

$9,900/MWh * 30 hours = $297,000/MW ≈ $300/kW

In fact, these or other scenarios will give rise to a similar financial impact, as demonstrated below.

Retail exposure to compensation cost

If we assume that all generators use the "guess the clearing price" bidding strategy on all of their capacity, then total compensation in a trading interval will be the premium multiplied by the total generation in the region or regions in which prices have been capped or (ignoring transmission losses and inter-regional flows[25]), the total demand in those regions. For simplicity, it will be assumed that prices are capped in all regions[26] so that:

NEM compensation in a trading interval ($) = price premium ($/MWh) * NEM demand (MWh)

EnergyAustralia will be required to pay a share of this total compensation, based on its market share:

EA payment ($) = NEM compensation ($) * EA demand (MWh)/NEM demand(MWh)

= price premium * NEM demand * EA demand/NEM demand

= price premium * EA demand

Since the major contribution to this $300/kW is likely to be at times of peak demand – when uncapped spot prices are likely to rise to VoLL or close to VoLL, the EA payment can be approximated using EA peak demand.

EA payment ($) ≈ premium * EA peak demand[27]

[25] These factors can be ignored as only a ball-park estimate of financial impact is being sought
[26] If an APP is declared in just one region and the spot price is capped in that region, is likely that prices will be capped in neighbouring regions to prevent counterprice flows (as required under 3.14.2(e) of the rules)
[27] Note that this result would be similar even if prices were capped in just NSW region, since the majority of EA demand is in this region.

The total EA payment over all trading periods in the APP is then:

$$\text{Total EA payment} \approx \Sigma(\text{premium} * \text{EA peak demand})$$

$$= \Sigma(\text{premium}) * \text{EA peak demand}$$

$$= \$300/\text{kW} * 4500\text{MW}$$

$$= \$1{,}350\text{m}$$

The compensation cannot be hedged, so this full amount would be payable by EnergyAustralia irrespective of its contract portfolio.

This compensation estimate assumes that all generators use the guess-the-clearing-price bidding strategy for all of their capacity and that they do it successfully so that the offer prices of dispatched generators are clustered around the uncapped spot price. In this respect, it represents a theoretical maximum which may not be credible. However, if we more conservatively assume that:

- Only 10% of generators use this bidding strategy; *or*
- All generators use this bidding strategy, but most restrain themselves to bidding at only 10% of the expected clearing price; *or*
- All generators bid guess-the-clearing-price but the expert panel only awards compensation at 10% of the difference between offer price and capped spot price;

EnergyAustralia would still see compensation levels around 10% of this theoretical maximum: implying an EnergyAustralia exposure of $135m.

As a comparison, EnergyAustralia's annual gross retail margin is $172m and its net retail profit is $33m. So the compensation amount might equate to between 4 and 40 years of retailing profits, depending upon how aggressively generators respond to the pay-as-bid opportunity.

Customer exposure

As noted in the main body of this document, a retailer may decide to recover the extra costs from its customers – assuming that it has the contractual and regulatory ability to do so. A typical EnergyAustralia residential customer has a peak demand of 2.5kW, so the maximum clawback from a customer would be:

$$\text{Customer Clawback} = 2.5\text{kW} * \$300/\text{kW} = \$750$$

Since the annual electricity bill for such a customer is $1100, this clawback would likely cause extreme customer disruption, and for many customers would create severe hardship. Even if

EnergyAustralia more conservatively assume that the compensation, and so the clawback is only 10% of the hypothetical maximum, the impact on customers – at $75 - is substantial.

Retail exposure to capped prices

Recall that the intent of the APP/CPT arrangements, as articulated by the RP, was to allow the market to clear as normal, except in the extreme circumstances when the CPT was triggered, after which market risk should be "tightly controlled". EnergyAustralia can evaluate whether this objective has been achieved by comparing the exposure to compensation calculated above to a retailer's exposure to the capped spot prices

EnergyAustralia will assume that a prudent retailer is normally fully hedged against extreme spot prices at peak, using a portfolio of swap and cap contracts. However, the extreme market events that triggered the CPT may also cause some of the hedge contracts to be ineffective, either because some FM clauses in the contracts are triggered or because of the financial distress of some contract counterparties.

IES found that it would take a loss of 2000MW of generating capacity over the peak summer period to generate spot prices sufficiently high to trigger the CPT[28]. EnergyAustralia will assume that this is the quantity of hedging contracts that become ineffective during the extreme market conditions. EnergyAustralia has a market share of the NEM of around 12%[29], and of NSW region of around 32%, so may hold between 12% and 32% of the ineffective contracts depending upon how diversified its portfolio is. EnergyAustralia will assume a share of 20% (being around the middle of this range) or 400MW, of these ineffective contracts and consequently may have exposure to 400MW to the extreme spot prices.

Therefore, EnergyAustralia's market risk of this period is approximately:

EA exposure = 400MW * $300/kW = $120m

In the event that there is forced load shedding, this will reduce the level of EnergyAustralia's peak demand and so reduce this exposure somewhat.

So, as a prudent retailer, EnergyAustralia may be exposed to of the order of $120m of spot price risk before and during an APP. To this risk is added exposure to compensation of between $135m and $1,350m. So, far from "tightly controlling" the risk, the APP/CPT arrangements allow risks to be inflated further.

Indeed, if the APP/CPT arrangements were abolished completely, and recalling under this scenario IES estimate the risk premium was around $600/kW, the price risk would become:

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[28] IES found that this loss of generation within a region would be sufficient to trigger the APP in that region. As discussed above, it is assumed here that this causes prices to be capped in all regions.

[29] Assuming an undiversified NEM peak demand of 38GW. Actual NEM peak demand will be somewhat lower than this due to region diversity and load shedding and so EA market share may be somewhat higher.

EA exposure = 400MW * $600/kW = $240m

Of course, under this scenario, there is no exposure to compensation, so the total exposure is $240m, compared to between $255m ($120m + $135m) and $1,470m ($120m + $1,350m) under the current APP/CPT arrangements. Therefore, the APP/CPT is unlikely to reduce the level of market risk and quite possibly will increase it, in the worst case substantially.

Retail exposure to cost-based compensation

Under the proposed rule change, compensation would be based on the difference between variable generating costs and capped spot prices. Given that the APC is $100/MWh in peak periods and $50/MWh in off-peak periods, the main recipients of compensation will be those whose variable costs are higher than $100/MWh. Baseload and mid-merit generation would mostly have lower costs than this, although costs may be higher in some instances – for example where they have cancelled a planned outage.

Hydro-generation would be compensated to the extent that any water used during the APP meant that they were unable to generate following the APP. However, the level of compensation depends upon the level of spot prices following the APP, which is uncertain.

There is around 3000MW of installed OCGT capacity in the NEM, with variable generating costs for continuous operation ranging from around $50/MWh for OCGTs using natural gas to around $300/MWh for those using distillate. Costs will be higher when start-up costs are included and gas costs may also be higher when the amount of running is much higher than expected, as may be the case during an APP.

Finally, there may be some demand-side management with costs higher than $100/MWh[30].

To estimate the cost-based compensation it is conservatively assumed that 4000MW of peaking plant will be compensated (including some demand-side management and some hydro, but excluding some gas-fired OCGT) at an average price of $500/MWh (to allow for some high-cost demand-side management and hydro and lower-cost OCGT).

EnergyAustralia first needs to estimate how many hours this capacity would be dispatched for during the APP, given the $300/kW of risk premium that accumulates during the APP. At one extreme, as noted above, the risk premium might be generated in only 30 hours of VoLL[31] with prices below the APC for the remainder of the time. At the other extreme, prices may be at $500/MWh for 1500 hours[32]. However, the latter is highly unlikely, as prices at this level would be

[30] Dispatched demand-side management would be eligible for compensation for any costs directly associated with load management.
[31] 30 hours * $10,000/MWh = $300,000/MW = $300/kW.
[32] 1500 hours * ($500/MWh - $300/MWh) = $300,000/MW = $300/kW.

barely sufficient to trigger the CPT[33]. It will be assumed that most of the risk premium is generated when prices are at or close to VoLL, giving an average uncapped spot price during price capped periods of $5000/MWh[34]. It would therefore take around 60 hours of price capping to generate the $300/kW risk premium[35].

The estimated cost of compensating the high-cost generation and demand-side management will therefore be:

$ Compensation = hours of running * capacity * (variable cost – APC)
= 60 hours * 4000MW * ($500/MWh - $100/MWh)
= $96m

If EnergyAustralia bears 12% (being its NEM market share) of the total compensation cost, its exposure to compensation under the proposed rule change is around $12m. Comparing this to the estimated $120m of exposure to market risk outside of the APP and also to the additional $120m of market risk that would have been seen had there been no APP, it is seen that the revised APP/CPT arrangements are now fairly effective at controlling risk during the APP. By comparison, worst-case compensation payments under the pay-as-bid scenario are around one hundred times higher.

Given EnergyAustralia's peak demand of 4500MW, or 4.5 million kW, the $12m compensation cost is equivalent to around $2.70 per kW of peak demand. Therefore, if EnergyAustralia sought to clawback this cost from customers, a typical residential customer with 2.5kW peak demand would be charged around $7, which would not cause significant disruption or hardship.

Comparison of pay-as-bid and cost-based exposure

The above sections have derived ball-park estimates of the amount of compensation payable by EnergyAustralia during an APP: $1,350m under a worst-case pay-as-bid scenario; $12m under the proposed cost-based compensation. It may be helpful to analyse the sources of these different values.

Firstly, in the cost-based scenario, it is assumed that generators are paid at an average cost of $500/MWh, of which $100/MWh is paid through the capped spot price and $400/MWh by the APP compensation. In the pay-as-bid scenario, it is assumed that generators are paid at the uncapped spot price, which averages $5000/MWh, of which $4900/MWh is paid as compensation.

Secondly, in the cost-based scenario, only generators with costs above the capped spot price are compensated: ie peaking generators and demand-side management with an assumed total

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[33] Even if uncapped spot prices were at $500/MWh for *every* hour of the day, the weekly cumulative price would only be 336*$500/MWh = $168,000: i.e. barely sufficient to trigger the CPT.

[34] By comparison, the $73/kW of risk premium that accumulated in NSW in winter 2007, for spot prices above a strike price of $500/MWh, was generated over 45 trading intervals, giving an average spot price over these hours of around $3200/MWh.

[35] 60 hours * $5000/MWh = $300,000/MW = $300/kW.

capacity of 4000MW. Under the pay-as-bid scenario, all generators are compensated at the uncapped spot price, since all can use the guess-the-clearing-price strategy to raise their offer prices to this level. So the capacity compensated may be around 38,000MW (ie NEM peak demand[36].

So, under cost based compensation, hourly total compensation (of which EA contributes around 12%) during periods of capped spot prices averages $400/MWh * 4000MW = $1.6m. Under the pay-as-bid assumptions, the hourly average is $4900/MWh * 38,000MW = $186m. This is another way of demonstrating that compensation under pay-as-bid is of the order of 100 times higher than cost-based compensation. The higher figure is a combination of the higher price at which compensation is paid and the larger volume of capacity which receives the compensation.

Summary

The above analysis provides some ball-park estimates of retail exposure to extreme market events, prior to and during and APP and with and without the proposed rule change. These estimates are summarised in the table below.

Scenarios	EA exposure ($m)	Cost per residential customer ($)
Current arrangements: worst case compensation	1350	750
Current arrangements: moderate compensation	135	75
Proposed rule change: cost-based compensation	12	7
Market risk outside of the APP	120	n/a
Market with no APP	240	n/a

Therefore the current arrangements are quite ineffective at controlling market risk, with total risks no lower, and potentially far higher, than if there were no APP price-capping at all. On the other hand, the proposed rule change will ensure that market risk during an APP is controlled to a reasonable level and one consistent with the objectives of the RP in proposing the CPT/APP arrangements.

[36] Again, using the undiversified total of the region peak demands which will overestimate actual NEM peak-time demand somewhat.

Appendix 2: Suggested Draft of the Proposed Rule

Energy Australia's Rule Change Request

Compensation provisions due to the application of an administered price, VoLL or market floor price

1 Title of Rule

This Rule is the *National Electricity Amendment (Compensation due to the application of an administered price, VoLL or market floor price) Rule [2008 No. #].*

2 Commencement

This Rule commences operation on *[insert date].*

3 Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

Schedule 1 Amendment of National Electricity Rules

[1] Clause 3.14.6 Compensation due to the application of an administered price, VoLL or market floor price

Clause 3.14.6(c) is deleted and replaced with the following:

> (c) The *AEMC* must determine whether it is appropriate in all of the circumstances for compensation to be payable by *NEMMCO* and, if so, the *AEMC* must determine an appropriate amount of compensation, taking into account the matters referred to in clause 3.14.6(e).

In clause 3.14.6(e), the words "The panel must base its recommendations on its assessment of a fair and reasonable amount of compensation taking into account:" are deleted and replaced with the following:

> The panel must base its recommendations as to whether it is appropriate for compensation to be payable, and if so its assessment of a fair and reasonable amount of compensation, in each case taking into account:

Clause 3.14.6(e)(3) is deleted and replaced with the following:

> (3) in the case of a claim by a *Scheduled Generator*, that the purpose of any compensation determined to be payable to a *Scheduled Generator* is to enable that *Scheduled Generator* to recover direct costs incurred in respect of *dispatched generating units* during the *administered price period* or *market suspension*, which costs are:
>
> (A) fuel costs in connection with the *scheduled generating unit*;
>
> (B) incremental maintenance costs in connection with the *schedule generating unit*; and
>
> (C) incremental manning costs in connection with the *scheduled generating unit*,
>
> to the extent the total of such costs is greater than any amounts the *Scheduled Generator* is entitled to receive under clauses 3.15.6 and 3.15.6A.

Insert the following new clause 3.14.6(f):

> (f) The *AEMC* must *publish*:
>
> (1) the panel's report; and
>
> (2) a draft statement setting out the determination the *AEMC* proposes to make pursuant to clause 3.14.6(c),
>
> and invite written submissions and comments from interested parties on the matters set out in the panel's report and the *AEMC's* draft statement, within a

period specified by the *AEMC*, being a period of not less than 20 *business days* from the date of publication.

Insert the following new clause 3.14.6(g):

(g) In making a final determination for the purposes of clause 3.14.6(c), as well as the matters referred to in clause 3.14.6(e), the *AEMC* must take into account (but will not be bound by) the panel's report and any submissions received pursuant to clause 3.14.6(f). The *AEMC* must publish its final determination.

[11.#] Rules consequent on making of the National Electricity (Compensation provisions due to the application of an administered price, VoLL or market floor price) [Rule 2008]

[11.#.1] Definitions

For the purposes of this rule 11.#:

Amending Rule means the National Electricity (Compensation provisions due to the application of an administered price, VoLL or market floor price) [Rule 2008].

Commencement date means the day on which the Amending Rule commences operation.

Former Rule means clause 3.14.6 of the *Rules*, in force immediately before the commencement date.

[11.#.2] Claims made by participants prior to commencement date

Where a claim for compensation was made by a *Scheduled Generator, Scheduled Network Service Provider* or *Market Participant* pursuant to clause 3.14.6 of the Former Rule prior to the commencement date, and the *AEMC* has not, as at the commencement date and in respect of that claim, determined pursuant to clause 3.14.6(c) of the Former Rule whether it is appropriate for compensation to be payable by *NEMMCO* or the amount of compensation, then such determination shall be made by the *AEMC* in accordance with the Former Rule.