Level 22
530 Collins Street
Melbourne VIC 3000

Postal address
GPO Box 2008
Melbourne VIC 3001

T 1300 858 724
F 03 9609 8010
E info@aemo.com.au

2 September 2022

Anna Collyer
Chair
Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

Dear Anna,

Amending the administered price cap, Consultation paper

AEMO welcomes the opportunity to provide a submission on the AEMC's rule change request from Alinta Energy to increase the administered price cap (APC) from $300/MWh to $600/MWh, published on 4 August.

AEMO supports a simple yet effective amendment, that will preserve the incentive for generators to continue to make supply available to the market notwithstanding a recurrence of the extreme fuel prices that contributed to the operational challenges and ultimately market suspension in June 2022.

Forward prices for fuel commodities indicate prices are likely to remain very high for some time. The APC should be set with this in mind acknowledging its role in providing short term market signals. For it to work effectively its needs to be able to enable market players to cover their short run marginal costs - sufficient to encourage reasonably efficient dispatch by allowing generators to recover fuel costs, minimise the need for AEMO intervention and hence assist in maintaining a secure power system.

In considering the appropriate APC level, it is important to note that temporarily increasing the APC does not mean higher overall electricity costs for hedged market customers. For this reason, temporarily increasing the APC should reduce overall electricity costs, and provide more transparency and certainty for the vast majority of electricity consumers.

AEMO notes that in the arrangements in the Western Australia Market, a formulaic approach is used. AEMO encourages the AEMC to consider this in its subsequent review of the APC. However, given the actual and potential system security risks demonstrated by the June events – an expedient, and temporary increase of the APC to $600/MWh should occur.

Any enquiries to this submission can be directed to Kevin Ly, GM Reform Development & Insights at kevin.ly@aemo.com.au.

Yours sincerely,

Violette Mouchaileh

Executive General Manager – Reform Delivery

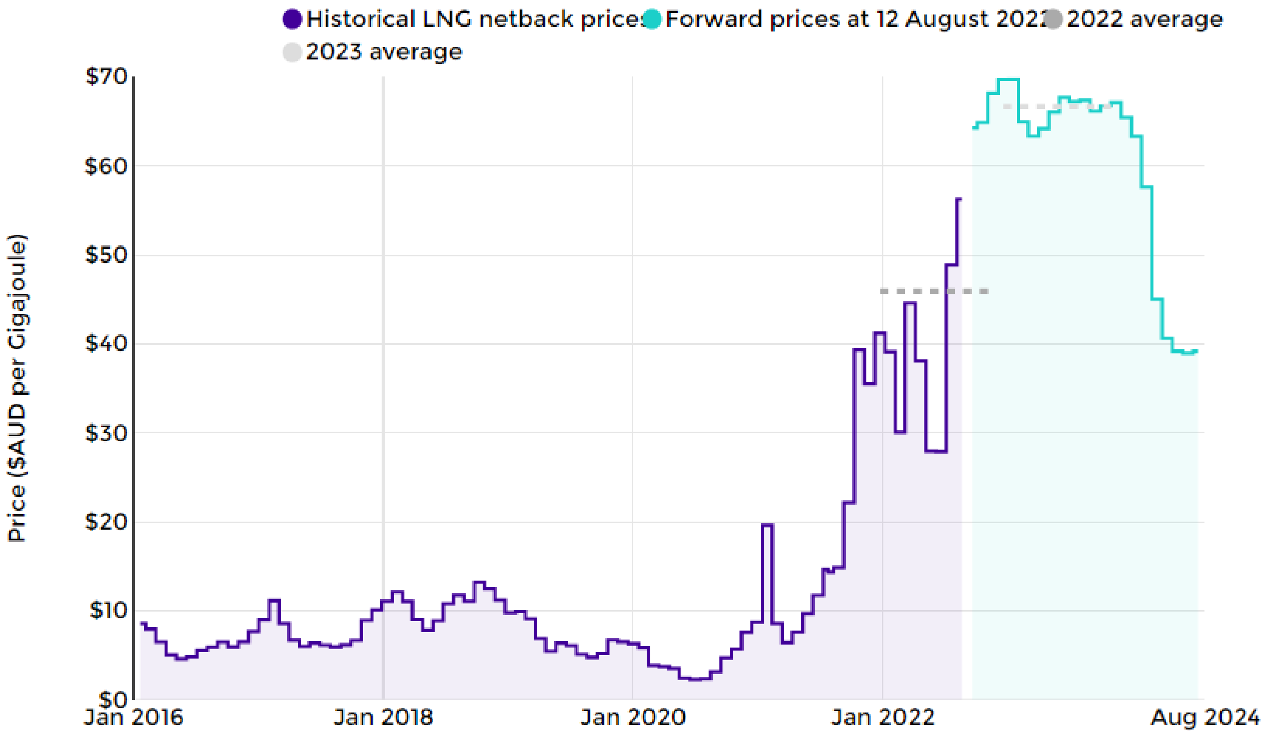
Attachment – responses to the consultation questions

This attachment discusses the general questions set out in the consultation paper but does not address all of them. For ease the attachment is set out in the same order as the consultation paper.

What is the problem the rule change is trying to solve?

AEMO considers the amendment proposal correctly defines a narrow problem of the APC being insufficient to pay for the prevailing short run marginal cost (SRMC) of many generators, and insufficient for the near term. This is clearly evidenced by Figure 1, which shows elevated gas prices now and the next two years. Failing to address the insufficiency of the APC could have negative economic effects if administered pricing were implemented again at the current APC and many generators' cost was more than that amount. A repeat of the events of June 2022 would not be in the interests of consumers, who benefit from a well-functioning electricity market.

Figure 1 – ACCC LNG netback timeseries



Given the amendment proposal is a simple change to the APC in the NER,[1] it can be implemented quickly and does not prejudice further amendments being made. It is therefore the best solution to a well-defined, narrow problem statement.

AEMO considers that this amendment should be made to avoid, or at the very least, minimise the operational challenges that led to the June 2022 market suspension. When administered pricing commenced, many generators withdrew capacity from the market, AEMO had to direct generating units to remain available, and the impact of multiple intervention constraints eventually led to AEMO suspending the market. Relying on continuous intervention to meet demand means that many of the automated dispatch and pre-dispatch processes cannot provide effective market signals, and the wholesale exchange cannot be effectively administered as contemplated by the NER. This in turn presents very real threats to the security and reliability

[1] NER clause 3.14.1(a)

of the power system, as illustrated in section 6 of AEMO's power system operating incident report for the June 2022 events[2].

This does not suggest increasing the APC is a perfect solution to problems exposed by the June 2022 market suspension.

As such, AEMO's support of the proposed amendment does not prejudice any comments AEMO may make to later processes that consider: generator bidding obligations; the operation of cumulative and administered pricing; changes to the form of the APC; the need to coordinate compensation frameworks; and measures to improve access to commodities. The APC can be increased temporarily, and these matters can be considered in due course.

What is an appropriate level of APC?

While it is clear the APC should be increased, determining the level of the APC is a more difficult question. The ACCC LNG netback price clearly indicates the possibility of gas prices being very high for the near term, higher than the current wholesale gas market administered price cap of $40/GJ. Further, the potential for a winter gas crisis in Europe is high, putting further pressure on supply and pricing. This should be considered in the context of the role gas-fired generation has in setting spot prices.

The NEM uses price caps in response to the inelasticity of electricity demand and to cap systemic risk in the sector. The reliability settings, MPC, CPT and APC are designed to create scarcity at the margin to provide for the Reliability Standard of 0.002% unserved energy per annum. So, while it is expected that the CPT and APC will at times apply, they are designed for relatively short duration capacity shortages and losses of load rather than increases in commodity prices as seen over 2021-2023.

The CPT and administered pricing are designed to reduce systemic risk in the sector, acting as a mutual insurance scheme where one participant accepts the protection from high prices that is offered to others, because it is also offered to them. When the CPT and APC apply, some participants will directly benefit over others, because that is the direct effect of capping prices below prevailing market value. By contrast, the CPT and APC cannot cap energy prices below SRMC for a significant share of the market's generating units without imposing significant inefficiencies in dispatch, administering compensation, or both.

The consultation paper[3] discusses the sufficiency of APC, with an assumed gas price of $40/GJ. The interaction of the administered price caps in the different markets is problematic. Market conditions in Q2 2022 demonstrated that, if the electricity APC is less than a converted equivalent gas APC, generators try to avoid buying gas and reduce supply to the electricity market. If the electricity APC is more than the converted equivalent gas APC, this could inflate demand for gas for power generation that can buy gas at $40/GJ and sell electricity at an equivalently higher price in the electricity market. This assumes both APCs operate simultaneously, however there would usually be a period where one APC operates, and another does not. During such a period one would expect the distortions of the cap in one of the markets to be exaggerated because the true market value for energy applies in the other.

Resolving to increase the price cap in one market and yet relying on a price cap in another may be problematic. Rather than relying on an effective gas market under a price cap, by assuming gas will be available at $40/GJ[4] when the LNG netback price is currently far higher, instead the electricity APC could be assessed by the AEMC considering the potential range of gas prices for the near term and ignoring the administered price cap of the wholesale gas markets.

An option could be to amend clause 3.14.1(a) to specify a simple formula referencing the gas APC, using a GJ/MWh heat rate conversion like the approach used in Western Australia[5]. The heat rate assumption,

---

[2] AEMO, *NEM market suspension and operational challenges in June 2022,* August 2022.

[3] P21, Consultation Paper

[4] A gas market parameter review follows the Reliability Standard and Settings Review – nothing in this submission should be taken imply any future findings of that review.

[5] See discussion, P11 AEMO Submission 7th July 2022, Reliability Standard and Settings Review, Draft Report https://www.aemc.gov.au/sites/default/files/2022-07/AEMO%20Draft%20Report%20submission%20June%202022%20RSSR.pdf

something like 14-18GJ/MWh (AEMC consultation paper, page 15), exceeding most gas-fired plant in the NEM[6], may include some margin higher than the vast majority of the open-cycle gas turbines to encourage efficient dispatch during administered pricing.

On balance, it is unnecessary to speculate on whether the $600/MWh is sufficient to encourage reasonably efficient dispatch during administered pricing, because $600/MWh is obviously better than $300/MWh. The opportunity for refining the APC, possibly using a formula linked to prevailing commodity prices, can follow this process.

The consultation paper also requests that submissions consider the possible effects on generator and retailer risk. Under administered pricing, generators can claim compensation, including opportunity costs. A price cap reduces the overall producer surplus, and an APC below producers' costs would act as a subsidy without a compensation scheme to pay for those direct costs. Lifting the price cap would increase the producer surplus and reduce the consumer surplus.

Notwithstanding the above, to understand the effect on generators and retailers, it is worth considering the effects of contracts traded in advance of settlement between producers and consumers, and that the costs of compensating generators are not paid by any one retailer, but on a per unit basis by all retailers. That is, compensation costs are "socialised".

A retailer that has procured contracts in advance for their retail consumption, or has an available generator that has an operating cost lower than the existing APC, is not directly exposed to the increase in the price cap. This retailer would benefit from the increase in the APC, because it avoids having to fund a share of the costs of compensation.

A retailer that has not procured contracts in advance for their retail consumption, or is relying on a generator that is unavailable, or has an operating cost higher than the existing APC, is directly exposed to the increase in the price cap. Without offsetting contracts or generation, this retailer will have to directly pay for the increase in the APC and will no longer benefit from other retailers funding compensation. If the retailer is also generating, it is exposed to its fuel cost,[7] and will no longer benefit from directly claiming compensation for its fuel costs being more than the existing APC, the costs of which would be funded by other retailers.

It is this dynamic of a higher APC better allocating costs to the parties that caused them, (i.e., the parties that have not procured contracts, have generators unavailable or which have costs more than $300/MWh), which makes increasing the APC desirable. It is also this dynamic that preserves, to a greater degree, efficient dispatch during an administered pricing period.

This is presented in Figure 2. The table assumes an open-cycle gas turbine cost of $500/MWh, with this being used to calculate compensation and to set the spot price under an assumed APC of $600/MWh.

There are two cases, for each APC assumption of $300/MWh or $600/MWh, where the market customer (retailer) has 100% or 0% of load hedged at $100/MWh.

Under the $300/MWh APC case, $30/MWh compensation is payable irrespective of whether the market customer has hedged their load. If hedged they pay $100/MWh plus $30 compensation, if unhedged they pay $300/MWh plus $30/MWh compensation.

Under the $600/MWh APC case, no compensation is payable irrespective of whether the market customer has hedged their load, because the APC is now above the $500/MWh cost of gas generation and the market clears. If hedged they pay $100/MWh, if unhedged they pay $500/MWh.

[6] https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en

[7] Pool (debits) and credits (generation) net off, leaving the retailer paying for fuel and receiving retail tariff.

Figure 2 – APC and the effect of contracts

Without hedges, consumer surplus increases due to loss of producer surplus

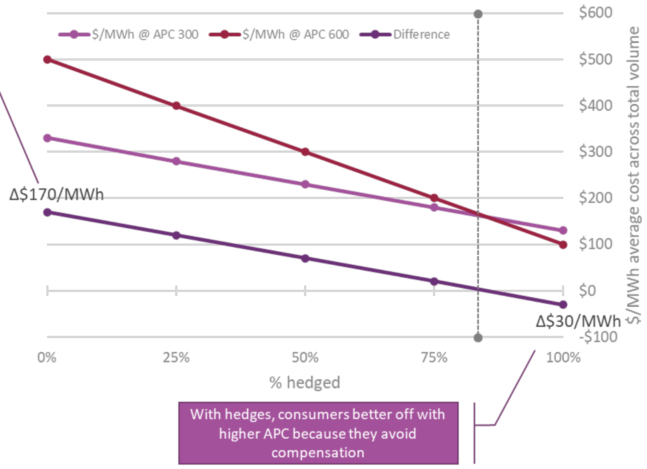
Spot price set by gas ($/MWh)	$500			
GPG 15% of energy	15%			
Hedge Strike Price ($/MWh)	$100			
APC $/MWh	$300	$300	$600	$600
Market Customer Hedge Level	100%	0%	100%	0%
Compensation (500-300) *15%	$30	$30	$0	$0
Market Customer Net Cost ($/MWh)	$130	$330	$100	$500

Faces hedge + $30 compensation

Faces APC + $30 compensation

Faces hedge only

Faces RRP only



Under the $600/MWh APC case, no compensation is payable irrespective of whether the market customer has hedged their load, because the APC is now above the $500/MWh cost of gas generation and the market clears. If hedged they pay $100/MWh, if unhedged they pay $500/MWh.

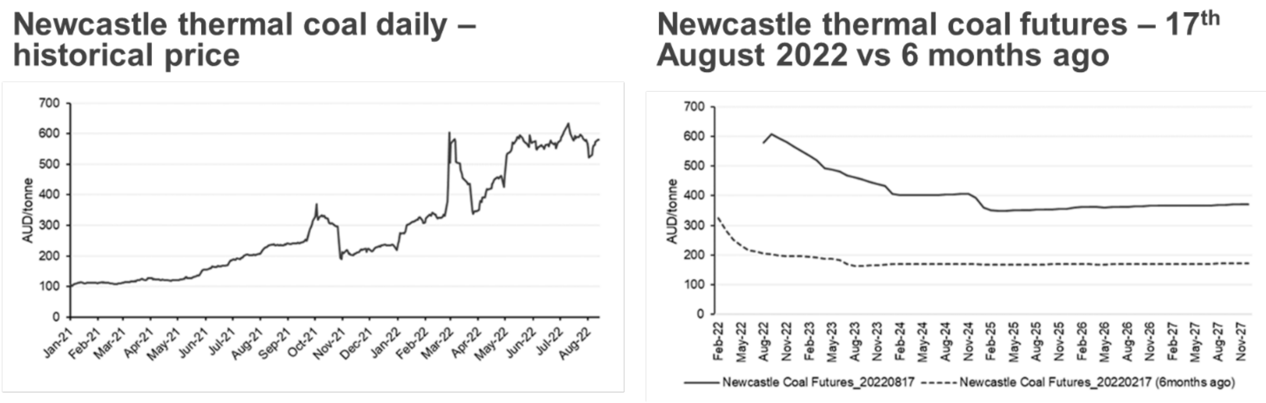
These examples are extended at different levels of hedging and presented in the chart. The chart clearly shows that market customers that have hedged prudently, as one would expect, are better off with the higher APC because they no longer face the costs of compensation, (these are costs caused by other market customers not hedging, or generators failing to make available or fuel their generator). The cross-over point using the assumptions in the table above is that market customers are better off with a higher APC if they are contracted/hedged above 85%. There follows in this submission discussion that suggests Market Customers / Retailers are risk adverse and prudent risk management of potential exposure to the spot price of MPC means a high level of hedging well above 85%.

So, although the CPT was designed to reduce risk for Market Customers (and Generators, that are unavailable) by capping prices and reducing the producer surplus in those instances, it was not designed to reduce risk by socialising generator fuel costs amongst all Market Customers when costs exceed the APC.

What is an appropriate temporary level of CPT?

Increasing commodity prices increase weekly average prices and reduce the buffer in accumulated prices before the CPT is breached. This is clearly indicated in the ACCC netback chart, Figure 1, and also Figure 3 which presents coal prices, all of which are elevated for the foreseeable future.

Figure 3 – coal prices and futures



Whilst the CPT could be increased to account for higher commodity prices, AEMO considers this to be out of scope, because the problem as described by Alinta is the insufficiency of the APC preventing efficient dispatch during administered pricing. AEMO notes the cumulative price threshold for FY22 was a *weekly* average price of $674/MWh. This price is above the proposed APC by Alinta and clearly shows, that from the proponent's description of the problem, the CPT is sufficient to allow for efficient dispatch. It should be remembered the June 2022 event was a conflagration of multiple generating unit outages and some transmission outages, particularly in the week preceding for QLD which breached the CPT first, and then followed in NSW the week after, with the remaining available generators at Eraring, Vales Point and Snowy suffering from energy limitations. This is in addition to the problem of the insufficiency of the APC.

Further, the CPT plays a different purpose. It is there to protect the market against systemic market risks from prolonged high spot prices irrespective of how these prices come about. While there may be increased likelihood of the CPT being breached due to these higher fuel prices, if a higher APC can preserve economic dispatch during administered pricing most of the time, for the majority of the scheduled generating units, breaching the CPT should not be a significant problem.

AEMO would suggest the primary problem is the insufficiency of the APC to pay for fuel costs, how this fails to preserve economic dispatch during APP and the potential for another suspension to occur. This should be resolved by increasing the APC, irrespective of whether it places the APC above the average CPT for a temporary period. Changing the CPT significantly broadens the assessment, detracts from the problem in hand, and should not be in scope.

For what period should a new APC and CPT apply?

Given this is largely dependent on how long commodity prices remain elevated, AEMO does not have a strong opinion on how long the temporary measure should apply. The amendment to the APC may need to apply for at least a year, and it would be useful to review it near cessation, assessing whether forward commodity prices have eased enough so the APC can be reduced with confidence that economic dispatch can be preserved for most generators during APP. In the interests of stability it may be sensible for the AEMC to consider whether and new APC should remain until commencement of the Reliability Panel's recommendations arising from the current Reliability Standard and Settings Review.

What are the likely benefits and costs from the proposed rule?

The benefits are twofold:

Firstly, if a region enters administered pricing a higher APC should be sufficient to cover the majority of generators' costs, encouraging them to make these units available and not withdraw them from the market. Without high levels of intervention by AEMO, the dispatch and pre-dispatch systems should continue to function effectively and provide effective signals for generators to purchase fuel and bid accordingly. This will be critical to avoid spiralling levels of intervention, and the serious power system security risks associated with the inevitable delays in response when generation dispatch must be planned manually and implemented by directions. Essentially, an APC that caters for supply costs under potentially extreme conditions should allow the market to continue operating as intended during administered pricing periods, and avoid another market suspension.

Secondly, a retail participant that is well hedged by derivative contracts, avoids having to pay as much compensation (because less is incurred in the first place) and will be hedged from the higher prices that follow increasing the APC. Conversely a retail participant that is not well hedged by derivative contracts or has a generator that is either unavailable or without available and cheap fuel will be more exposed to the costs they have caused and will be encouraged to remedy their position – possibly by generating.

With respect to contract market and financial requirements, AEMO would expect the market has already adjusted the value of contracts according to the likelihood the amendment being made, whether another administered pricing event will occur how long the amendment would apply. Given the AEMC has accepted the amendment proposal as urgent, and that the reasons for expediting the proposal are like those determining in favour of it, it is possible the forward curve may already assume a $600/MWh APC.

The consultation paper[8] discusses how the change to the APC changes the exposure of traders and the value of the $300 cap product. AEMO considers this to be true, and although one would expect sellers of caps to account for this as stated in paragraph above, a far more dramatic change to the value of caps has been the increasing cap payout associated with increasing gas prices. A seller of the $300/MWh cap may now have fuel costs above $300/MWh and must account for these in the cap premium. This means a product that is expected to have price volatility or capacity costs, now has a significant proportion of costs associated with the direct provision of energy. With fuel costs increasing beyond the traded cap price, this dynamic is broken, and this traded product is becoming less useful – this has a direct parallel with the APC, however it applies in all periods, not just during administered pricing. It is for this reason AEMO would presume any change in the value of the APC would change the exposure of prior sellers, (that entered a transaction prior to this proposal), by far less than the change in commodity prices over 2022 has done.

This leads onto the next point in the consultation paper, which suggests generators with short (sold) positions would need to fund their exchange positions if contract prices increase. Again, whilst this is true, the step change in the forward curve occurred earlier this year, and generators would have had to fund these short positions as the forward curve increased. Usually, an increasing forward curve is good for generators, however funding these positions could limit trading. This was because the forward curve continued to increase beyond anything seen before, and with the curve increasing further, additional trades may exacerbate the funding requirements. By comparison, the consequences of changing the APC would be immaterial and largely accounted for anyway.

A separate, but similar point, is raised in relation to OTC clauses[9]. Such contracts may allow for the counterparties to renegotiate associated with market disruption or change in law. Yet most contracts may not reference the APC directly for settlement purposes - because it is a price cap applied to the regional reference price used in settlement, the contract need only specify the relevant regional reference price.

Retail approaches

Retailer hedging strategies are commercially sensitive. However, AEMO expects retailers use hedging to reduce the risks associated with selling electricity on a fixed retail tariff when buying electricity from the spot

[8] P25, Consultation Paper

[9] P25, Consultation Paper

market. For example, a retailer may hold swap contracts covering around 95 per cent or more of its physical requirements and cover the remainder with caps or other derivative contracts, in order to limit its risk.[10] Alinta Energy has previously indicated that retailers generally aim to hedge conservatively, usually to a 1 in 20-year event, to ensure they are covered for extreme price events.[11]

Hedging strategies are estimated as part of the calculation of the Default Market Offer (DMO) and the Victorian Default Offer (VDO). In 2021, Frontier Economics published a report[12] to advise the Essential Services Commission (ESC) for the purposes of determining the VDO. The report considered the hedging contracts that a prudent retailer would likely enter into. It concluded that in general, the contract position at the conservative point involved purchasing swaps to cover average demand and caps to cover peak demand.[13] In the AER Final Determination on the DMO for 2022-2023, the AER sought to model a risk-averse retailer that had reduced its exposure to the possibility of very high spot market price. The AER considered that in usual market conditions most retailers would seek to reduce exposure to risks.[14] Most stakeholders agreed that that the AER's current risk-averse settings remained appropriate to set the hedging strategy when estimating wholesale costs.[15]

While electricity prices are expected to remain high for the foreseeable future, hedged retailers should not see these costs reflected for one to two years. The most traded swap is a quarterly "baseload" (1 MW for each hour in the quarter).[16] In the year to 30 June 2019, quarterly baseload swaps comprised the majority (67%) of ASX-traded contracts. When a retailer releases an offer to the market, it is likely the retailer estimates the wholesale price based on a hedged portfolio of contracts resulting in minimal spot market price risk for the coming 12 months.[17] If Q2 2022 trends continue,[18] contract prices will increase. If wholesale prices increase further in 2022 and demand is increasingly "peaky", the cost of hedging may be driven up, adversely affecting retailers.[19] However, retailers will likely continue to engage in risk-averse hedging practices.

Prudentials and settlements

Due to the 4-week settlement cycle, and time needed to suspend a market participant in the event of a default, AEMO needs to protect creditors by holding bank guarantees and security deposits provided by debtors. The amounts are calculated using historic price outcomes by season, using a participant risk adjustment factor which accounts for the correlation of the participants' purchases with higher prices, which is then multiplied by expected debit volume per week. This forms the amount that must be lodged on an ex-ante basis with AEMO. For these ex-ante calculations, the APC value is not a primary consideration. At any time, should outstanding amounts exceed the ex-ante amounts, security deposits or bank guarantees must be provided to offset this.

It is only if administered pricing occurs again that a higher APC of $600/MWh would have any effect, due to participant outstandings potentially being higher than they would have been with a $300/MWh cap.

In summary therefore, changing the APC will not change prudential arrangements, apart from the obvious effect of changing the amount owing to AEMO if a breach of CPT occurs again.

[10] Government of Western Australia Department of Finance Public Utilities Office - Electricity Market Review Options Paper 2014 p48

[11] Australian Energy Market Commission Advice on Best Practice Retail Price Regulation Methodology EMO0027 – Alinta Energy submission 2013 p4.

[12] Wholesale Electricity Costs - A final report for the Essential Services Commission 22 October 2021

[13] Wholesale Electricity Costs - A final report for the Essential Services Commission 22 October 2021 p35

[14] Australian Energy Regulator – Default Market Offer Prices 2022-2023: Final Determination p19

[15] Australian Energy Regulator – Default Market Offer Prices 2022-2023: Final Determination p26

[16] Victoria Energy Policy Centre – Victoria University – Do wholesale electricity prices pass-through to consumers in contestable retail electricity markets? An examination in Victoria, Australia p3

[17] Victoria Energy Policy Centre – Victoria University – Do wholesale electricity prices pass-through to consumers in contestable retail electricity markets? An examination in Victoria, Australia p7-8

[18] AEMO Quarterly Energy Dynamics Q2 2022 p22

[19] Australian Energy Regulator – Default Market Offer Prices 2022-2023: Final Determination p2

Implementation costs and timeframes

NER 3.14.5(e)(3) requires AEMO to publish the market suspension pricing schedule at least 14 days before the first day of the schedule. AEMO would also need to follow normal change management, testing in pre-production systems for a week. There is no requirement to change consulted procedures for a change in the value of the APC. AEMO can therefore implement a change with a minimum notice of three weeks, although this may vary depending on the exact day the notice is given.