AUSTRALIAN ENERGY COUNCIL

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22 June 2023

National Electricity Amendment MPC, CPT and APC Rule – Consultation paper

The Australian Energy Council welcomes the opportunity to make a submission to the National Electricity Amendment MPC, CPT and APC Rule – Consultation paper (Consultation paper).

The Australian Energy Council (AEC) is the peak industry body for electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. AEC members generate and sell energy to over 10 million homes and businesses and are major investors in renewable energy generation. The AEC supports reaching net-zero by 2050 as well as a 55 per cent emissions reduction target by 2035 and is committed to delivering the energy transition for the benefit of consumers.

(1) Market Price Cap (MPC) and Cumulative Price Threshold (CPT)

The MPC and CPT are two of the most fundamental components in the competitive market design of the NEM. This is evidenced by the volume of work that is undertaken by the Panel and stakeholders as part of its reviews. They are the mechanisms that provide generation and storage the necessary investment signals to ensure the reliability standard is maintained. While also ensuring they are set at the minimum levels that are required to limit cost impacts on consumers and unmanageable price risk for participants.

The AEC supports the Panel's conclusions on the need to increase both the MPC and CPT. To arrive at the proposed increases the Panel and its consultants conducted extensive and rigorous analysis and conducted substantial stakeholder consultation. In its Final Report the Panel stated that:

"The Panel's final recommendation, in respect of the review period 1 July 2025 to 30 June 2028, should be interpreted as the first step in a longer-term adjustment in the market prices settings to achieve MPC/CPT that are sufficient to incentivise:

- *investment consistent with the reliability standard in all NEM regions, and*
- *investment in the storage required to manage reliability risk in a high VRE power system."*[1]

[1] https://www.aemc.gov.au/sites/default/files/2022-09/2022%20RSS%20Review%20Final%20Report%20%281%29.pdf

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It is clear from the Panel's work that the existing MPC and CPT are too low to support marginal new entrant investment and if they are not increased the reliability standard of .002% unserved energy (USE) is likely to be breached. Furthermore, the changes are designed to support the necessary storage investment to allow a high VRE power system to function reliably. Hence, these changes are critical in facilitating the energy transition.

The Panel's proposed increase to the MPC and CPT represent a measured and least cost approach to setting these parameters as the values they have chosen are at the lower end of the ranges that the analysis indicated. As stated by the Panel:

"According to the Panel's modelling, the proposed increase is the minimum level required to support investment in generation, storage and demand response needed to avoid exceeding the reliability standard in light of thermal generator retirements after 30 June 2028."[2]

(2) Administered Price Cap (APC)

The AEC does not support changing the APC to \$500/MWh. Instead the AEMC should retain the \$600/MWh that it implemented on 1 December 2022.[3] Increasing the APC from \$300/MWh to \$600/MWh was a significant change for the market to absorb and a necessary one. Regulatory predictability and stability are extremely important for markets and the AEC can see no justification for impinging on these attributes by unnecessarily changing the level of the APC again.

The AEMC's decision to increase the APC to \$600/MWh until 30 June 2025 has resolved the problem of an inadequate APC level. The AEMC clearly demonstrated with \$42/GJ delivered gas prices and diesel costs of \$39.41/GJ, 3,000 MWs to 3,5000 MW of generation has a Short-Run-Marginal-Cost (SRMC) that exceeds the \$600/MWh APC.[4] At an APC of \$500/MWh this increases to 5,000 MW. Therefore, why change the APC again by lowering it such that an additional 1,000 MW to 2,000 MW will exceed it? This is particularly the case given many claims arising from the June 2022 APP are still yet to be finalised.[5]

The other benefit of retaining the \$600/MWh APC is that it is more likely than a \$500/MWh APC to facilitate a dynamic market during an APP. Otherwise the administered market's price will stay relatively close to the APC hence limiting price arbitrage opportunities for storage. This benefit is going to become increasingly important as more storage enters the market. Increased storage is critical for a functioning market as the transition to lower emissions introduces more VRE and less thermal generation is available. The AEC is of the view that the \$600/MWh is the only option satisfies both the current and expanded NEO (i.e., emissions objective).

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[2] Ibid.
[3] https://www.aemc.gov.au/rule-changes/amending-administered-price-cap
[4] https://www.aemc.gov.au/sites/default/files/2022-08/Amending%20the%20administered%20price%20cap%20-%20Consultation%20Paper%2010%20aug%20246%20pm.pdf
[5] https://www.aemc.gov.au/our-work/apc-claims/june-2022

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The AEC considers that if the APC is regularly reviewed, it is not necessary to be set based on expected inflation.

(3) AEMC's Decision-making Framework and Considerations

There appears to be some inconsistency of approach within the AEMC in that it recently decided to extend the interim reliability measure (of 0.0006% USE) out to 2028 without economic justification. While the IRM is used to trigger the Retailer Reliability Obligation (RRO) and not to determine the market settings it still increases costs for consumers for no tangible benefit in return. In its IRM decision the AEMC rejected concerns around additional costs for consumers.[6] The Panel considered more conservative reliability standards (albeit not as conservative as the IRM) and decided they did not "advance the NEO in a materially better way"[7] than the 0.002% USE reliability standard.

For this rule change the AEMC:

> *" … particularly intends: to consider if the benefit with a reduction in expected future levels of unserved energy justifies the consumer price impact of a higher MPC and CPT."*[8]

While there is no apparent economic rationale for targeting the IRM as a reliability standard the AEMC has decided to extend it for the RRO. In contrast, there is an economic rationale for pursuing the Panel's MPC and CPT recommendations to meet the less conservative (and less costly) 0.002% USE reliability standard. Furthermore, it appears the AEMC is proposing to reprocess the Panel's work which included detailed analysis utilising the AER's Value of Customer Reliability (VCR) results in determining the level of the USE at a level where the tradeoff between reliability and cost is acceptable to consumers.

The AEMC is proposing to consider jurisdictional and Commonwealth support schemes as part of this rule change process. With respect to the Commonwealth's planned Capacity Investment Scheme (CIS) albeit with limited detail currently available, the AEC would like to point the AEMC to its recently published report by consultants CEPA, *Adjustments to the market price cap in presence of a capacity mechanism*.[9] The AEC commissioned this work to help it understand (in theoretical terms) the implications of the introduction of a capacity market in parallel with the energy only market. The primary focus of the report was engaging with the theoretical claim that generators could be compensated twice for the capacity they provide – once through the existing energy market, and again through the capacity market (ie, "double-

[6] https://www.aemc.gov.au/sites/default/files/2023-05/Review%20of%20the%20IRM%20-%20EPR0090%20-%20Final%20report_for%20publication.pdf

[7] https://www.aemc.gov.au/sites/default/files/2022-09/2022%20RSS%20Review%20Final%20Report%20%281%29.pdf p.56.

[8] https://www.aemc.gov.au/sites/default/files/2023-05/ERC0353%20-%20Consultation%20paper.pdf. p14.

[9] Attached to this submission and can be found online at: https://www.energycouncil.com.au/media/y0elhbvl/cepa_aec_finalreport.pdf

dipping”). While the CIS is not the same as the capacity market assumed in the CEPA report, there are many parallels, and their analysis and conclusions provide useful insights.

The simplest learning from the CEPA ‘s analysis is that in a competitive market there is essentially a fixed amount of revenue required by the market and the source of this revenue is not relevant. Hence, if the market is bifurcated through the introduction of a capacity market alongside the existing energy only market, total revenue is unchanged.

In a scenario where the MPC and CPT are lowered, revenues from the energy only market would decrease and this decrease in revenue would be matched by an increase in revenue for the capacity market. Applying this scenario to the introduction of a CIS implies that the CIS will be more costly as the energy only revenue losses would need to be recovered through it. Each of these outcomes generates the same total revenue as an energy only market. However, less of the revenue is determined through competitively efficient means and more accrues to the subsidised centrally planned schemes. This results in an inferior outcome for consumers as they pay the same price as an energy only market plus the subsidies for the schemes.

Any questions about this submission should be addressed to me directly, by email to peter.brook@energycouncil.com.au or by telephone on 03 9206 3103.

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Adjustments to the market price cap in presence of a capacity mechanism

Final Report

Australian Energy Council

14 September 2022

Important notice

Contents

1. SUMMARY 4
2. INTRODUCTION 7
3. AN OVERVIEW OF ENERGY-ONLY AND CAPACITY MARKETS 9
   3.1. Energy-only markets 9
   3.2. Energy plus capacity markets 10
   3.3. The National Electricity Market 10
4. A THEORETICAL ASSESSMENT OF DOUBLE-DIPPING 12
   4.1. Offering behaviour of market participants 12
   4.2. An example of offers reflecting marginal costs net of marginal revenues 13
   4.3. The theory as applied to capacity and energy market 15
5. ASSUMPTIONS AND FURTHER ANALYSIS 18
   5.1. Simultaneous outcomes in both markets 18
   5.2. Inelastic demand 18
   5.3. The mpc being set at the appropriate level under the energy only market 20
   5.4. Competition and market power concerns 21
   5.5. Changes to the cost of capital 22
6. EVIDENCE TO SUPPORT THE THEORY 25
   6.1. Essential system services 25
   6.2. Large-scale generation certificates 26
   6.3. Price caps in capacity markets internationally 27
7. QUANTATIVE ANALYSIS 28
   7.1. Simplified model 28
   7.2. Market modelling 29
APPENDIX A 31

1. SUMMARY

Governments are currently considering introducing a capacity market to the National Electricity Market (NEM), to supplement the existing energy market. Through this capacity market, market participants would be directly paid for the capacity they provide.

Some commentators have suggested that the energy market price cap should be lowered upon the introduction of a capacity market, because otherwise generators would be compensated twice for the capacity they provide - once through the existing energy market, and again through the capacity market. This has been termed "double-dipping" and is the focus of this report.

The term "double dipping" implies that the concern of stakeholders is more specific than the general concern that generators would exercise market power in either the capacity market, energy market or both. We understand the specific concern to be that prices and revenues received in the capacity market would not reflect prices and revenues received from the energy market and vice versa, resulting in higher overall revenues for generators.

Offers are based on net marginal costs meaning that double dipping should not occur

In perfectly competitive markets, profit maximising market participants offer at prices equal to the marginal cost imposed on the seller of producing an additional unit of the good or service, *net* of the additional revenue expected to be received from the sale of any by-products (and vice versa). The reason for this is simple:

- offering at a price lower than marginal costs net marginal revenues received from the sale of the by-product risks selling at a loss, because the collective revenue received from the sale of both products is less than the cost of producing them.
- offering at a price higher than the marginal costs net marginal revenues risks a competitor making the sale instead, with no prospect of raising the clearing price in a perfectly competitive market.

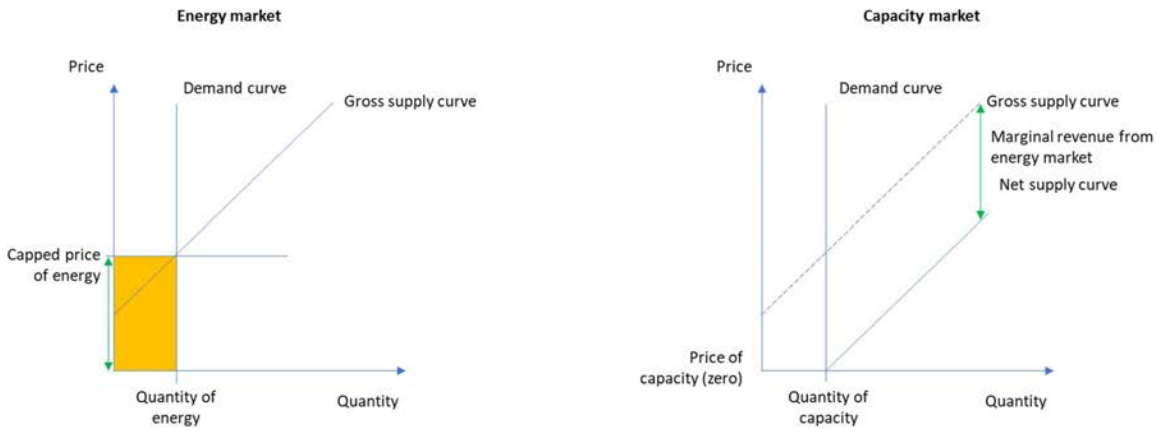
No market is perfectly competitive, and in practice in determining their offer price, a market participant seeks the optimal trade-off between higher prices and lower quantities which maximise their overall profits. Even so, profit maximising offers are based on (even if not equal to) net marginal costs, not gross marginal costs. Not offering on this basis would fail to adequately consider the likely offer prices of competitors who would be basing their offers on net marginal costs, leading to a sub-optimal trade-off for the market participant between price and quantity, and less profitable overall outcomes.

Prices and revenues received in the capacity market should therefore in theory reflect prices and revenues expected to be received from the energy market. Economic theory suggests that double-dipping would not occur, and so lowering the energy market price cap on this basis is not appropriate.

All else equal, changing the market price cap should have no impact on physical or financial outcomes

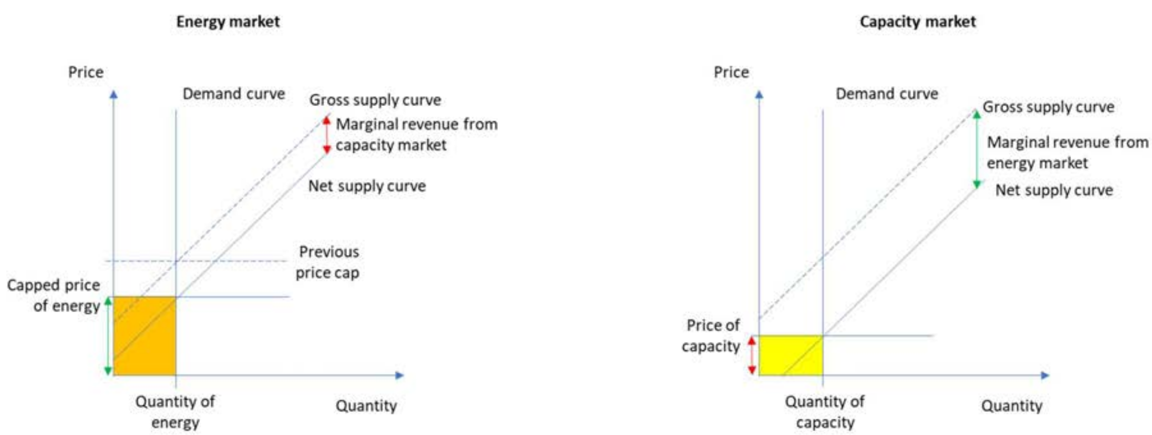
In an energy-only market with a sufficiently high market price cap (Figure 1.1), all of the revenue is recovered through the energy market (and ancillary markets) and so a capacity market is redundant. There is no "missing money" to justify the creation of a capacity market: the gross marginal cost of supplying capacity is offset by the marginal revenue received from the energy market, resulting in low offers and a clearing price in a (hypothetical) capacity market of zero.

Figure 1.1: Energy only market



Lowering the market price cap in the energy market creates "missing money": prices are inadequate to make investment in generation capacity profitable which leads to inadequate generation. This in turn justifies the introduction of a capacity market. Lowering the market price cap in the energy market would have the effect of lowering marginal revenues from the energy market, in turn increasing net marginal costs and so offers and prices in the capacity market (Figure 1.2).

Figure 1.2: Energy market plus capacity market



Changing the market price cap changes the proportion of revenue recovered via the energy market and capacity market. However, all else equal the quantity of energy, capacity, unserved energy and overall revenue received across both markets should in theory all be unchanged by reducing the energy market price cap below that required to satisfy the reliability standard via the energy market alone.

Low market price caps drive the need for capacity markets, not the other way around

The argument that a lower energy market price cap is appropriate upon the introduction of a capacity market may be being made because of the observation that relatively low energy market price caps are – or were – commonly associated with capacity markets. However, it is not the case that low market price caps are a necessary feature of well-designed energy markets given a capacity market. Instead, the direction of causation is that the low market price cap creates missing money that then needs to be addressed via a capacity market in order to deliver the desired level of reliability. Low market price caps justify capacity markets, not the other way around.

Lowering the market price cap for other reasons may be appropriate but comes with trade-offs

A major component of the ESB's argument in support of a capacity market is that its introduction will reduce the cost of capital, ultimately improve price and/or reliability outcomes for consumers. Because reducing the energy market price cap has the effect of increasing the revenues that flow through the capacity market, an overall reduction in the cost of capital might therefore be achieved by lowering the market price cap and increasing the relative size of the capacity market. But this is not an argument in favour of lowering the market price cap to avoid "double dipping". If the overall cost of capital is reduced, then this would be reflected in a lowering of the gross costs to provide capacity and energy. Generators acting in a profit maximising manner would still offset this (lower) gross cost by the marginal revenue expected to be received in the energy market when bidding in the capacity market.

While a reduction in the cost of capital might be achieved by lowering the market price cap and introducing a capacity market, there are substantial trade-offs with this approach:

- By reducing the risk for investors, much of the inherent risk in the sector (for example relating to uncertainty about demand for electricity) has been transferred onto consumers. Lower prices, should they arise, come at the expense of higher risk for consumers. Like investors, consumers are also risk averse, and so it is not clear that the risk-price trade-off is in their long-term interest.
- Investment decisions are increasingly made by central agencies such as the system operator that do not bear their financial consequences of those decisions. Indeed, central agencies may have incentives to deliver inefficiently high levels of reliability, increasing total system costs and prices for consumers. This effect may in practice exceed the reduction in prices arising from reducing the cost of capital, leading to an overall increase in costs for consumers.
- A lower market price cap can lead to numerous operational inefficiencies which in turn may also flow through to investment inefficiencies – both of which exacerbate reliability problems and increase costs and prices.

2. INTRODUCTION

Government agencies are currently considering introducing of a capacity market to the NEM.[1]

Via this capacity market generators, storage and demand response would be directly paid for their capacity to provide generation or demand response. This would represent a significant change to the NEM's existing energy-only market design, where market participants are only paid for energy actually produced.[2]

Some stakeholders have suggested that a lower market price cap in the energy market is appropriate upon the introduction of a capacity market in the NEM. These stakeholders appear concerned that without lowering the cap, generators may continue to receive high revenue in the energy market and additional revenue through the capacity market – so-called "double dipping" – at the expense of consumers. For example, the Energy Users Association of Australia (EUAA) stated in its February 2022 submission to the ESB that:

> *"It is the firm view of many EUAA members that with the introduction of a capacity market, where capacity payments are provided in order to encourage investment in the right form of asset, there can be no justification for maintaining the MPC at its current level. The key concern is that by providing capacity payments and a high MPC we are effectively rewarding assets twice, leading to unnecessarily high costs for consumers."*[3]

The term "double dipping" implies that the concern of stakeholders is more specific than the general concern that generators would exercise market power in either the capacity market, energy market or both. We understand the specific concern to be that prices and revenues received in the capacity market would not be reflect prices and revenues received from the energy market and vice versa, resulting in double payment.

CEPA has been engaged by the Australian Energy Council (AEC) to consider whether a relatively high market price cap and other market settings[4] in the presence of a capacity mechanism would result in double payment for capacity at unnecessary customer cost.

This report:

- provides a brief overview of capacity markets and energy only markets in order to contextualise the discussion (section 3)
- provides a detailed discussion of the theory of whether generators would be expected to double-dip upon the introduction of the capacity market in additional to the NEM's existing energy market (section 4). A mathematic description of this theory is provided in Appendix A
- discusses and analyses key assumptions relating to this theory (section 5)
- provides real-life evidence of the theory in practice in other contexts (section 6).

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[1] In September 2021, Energy Ministers agreed at the Energy National Cabinet Reform Committee for the Energy Security Board (ESB) to progress further design work on a mechanism that specifically values capacity in the NEM. In August 2022, Ministers instructed instruct Senior Officials to propose options for a framework that delivers adequate capacity, ensures orderly transition, and incentivises new investment in firm renewable energy to ensure the system can meet peak demand at all times. While there may be some changes to the design of the capacity market compared to the detailed design published by the ESB in June 2022, we have for the purposes of this report assumed a capacity market design consistent with June 2022 design. We consider it unlikely that any changes to the design of the capacity market will substantially affect the conclusions of this report.

[2] In practice, the NEM has a features which mean that the energy-only market label is not strictly accurate. This is discussed in section 3.3.

[3] https://www.datocms-assets.com/32572/1645744451-euaa-response-to-capacity-mechanism-project-initiation-paper.pdf.

[4] The market settings are the market price cap, market floor price, the administered price cap (a temporarily lower price cap applied when prices have been sustained at high levels over the time) and the cumulative price threshold (the threshold which determines whether the administered price cap applies). Focus in the report is on the market price cap, although the arguments in this report applies equally to the other market settings.

CEPA has also been engaged to:

- develop a simple model to aid the demonstration of the theory. This model is highly stylised and does not attempt to accurately represent real conditions in the NEM. An overview of the model is provided in section 7.1. The model itself has been provided to the AEC separately
- comment on how to develop a more complex model which more accurately reflects the real conditions of the NEM (section 7.2).

3. AN OVERVIEW OF ENERGY-ONLY AND CAPACITY MARKETS

In most commodity markets the price of the commodity is determined through buyers and sellers agreeing on a price at which to transact. Consumers themselves make their own, individual trade-offs between price and the value they derive from consuming the commodity.

Electricity markets do not typically feature an active demand side responding to real-time prices. For consumers to make individual trade-offs between the real-time price and the value they place on consuming electricity requires real-time pricing information (noting that energy prices change every 5 minutes in the NEM), adjusting consumption in response to these prices, and sophisticated metering. While technological change such as the internet and automation is diminishing these issues they still remain a substantial barrier for many consumers.

As a result, in electricity markets there is a centrally determined appropriate quantity of energy or capacity (a "reliability standard"), which seeks, on behalf of consumers, to trade-off the cost of supply against the value of consumption. In the NEM, the reliability standard is a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.[5] Furthermore, energy prices are capped in recognition that consumers may not themselves curtail demand in response to high prices.

Two main designs have emerged in practice which seek to deliver the centrally determined reliability standard – energy-only markets and energy markets plus capacity markets. These are briefly discussed below.

3.1. Energy-only markets

In an energy-only market design, generators are only paid for energy actually delivered. To induce sufficient capacity in the system to meet occasional tightness in the supply-demand balance and deliver the appropriate level of system reliability, market prices need to be able to rise considerably at these times. This allows so-called "peaking" generators that provide energy at times of tight supply, but that are otherwise largely idle, to recover their fixed and variable costs. Without being able to recover their fixed and variable costs, peaking generators would not be profitable, and investors would be unlikely to invest in them – resulting in systematic underinvestment in capacity compared to the reliability standard. Consequently, energy-only markets are characterised by high market price caps, determined at a level to induce investment consistent with meeting the reliability standard, but no higher in recognition that many consumers do not actively respond to real-time prices.

Because real-time energy prices can get very high, but peaking generators are only infrequently required to generate, generators and market customers[6] typically enter financial contracts or vertically integrate with one another to manage their respective risk. Many of these contracts – such as "cap" contracts – involve payments between counterparties regardless of whether energy is actually delivered to the system. For the retailers, this protects against the risk of very high real-time prices which arise when there is tightness in the supply/demand balance. For the peaking generators, this protects against the risk of plentiful supply and hence not being required to physically deliver energy.

The label "energy-only market" therefore refers to the fact generators are only paid (and market customers only pay) for energy in the market administered by the market operator. Capacity is nevertheless paid for via a decentralised capacity market - the contract market. This market, if functioning properly, provides an efficient signal to investors.

[5] National Electricity Rules, clause 3.9.3C(a).

[6] Market customers are those that buy from the wholesale market – typically retailers.

3.2. Energy plus capacity markets

In energy market plus capacity market designs, the energy market is supplemented by a capacity market or capacity mechanism. Market participants transact on the energy generated and consumed, but additionally there are markets or regulations with the specific purpose of providing additional capacity above and beyond that which would be prompted by the energy market alone.

There are various capacity market or capacity mechanism designs internationally, but the approach considered by the ESB involves a central agency – AEMO – directly entering contracts with generators, storage and demand response for the provision of capacity.

The key rationale for a capacity market is the so-called "missing money problem" that may arise in energy-only markets. To our knowledge, this term was first coined by Crampton and Soft in 2006:

> *"The central problem, labelled "missing money," is that, when generating capacity is adequate, electricity prices are too low to pay for adequate capacity. This problem is recognized by all capacity-market approaches. …The consequence of this problem is a long-run average shortage of capacity and too little reliability."*[7]

One of the main causes of the missing money problem is energy market price caps that are too low to incentivise investment in efficient levels of generation capacity. Low market price caps curtail the revenue that sufficient peaking generators require to be profitable (taking into account all costs, including a risk-adjusted cost of capital) in an energy-only market – resulting in systematic under-investment in capacity and levels of reliability below the reliability standard. Capacity markets are therefore required to plug the missing money arising from low market price caps.

Internationally, and in the Western Australian Energy Market (WEM), capacity markets were therefore typically accompanied by relatively low market price caps (or offer caps) in the energy market – although to be clear, it is the low energy price cap which prompts the need for the capacity market, not the other way around. Furthermore, in practice, many markets internationally which have capacity market have introduced administratively determined "scarcity pricing mechanism" which can result in relatively high market prices. For example, in PJM, which has a capacity market, there is:

- no energy market-wide price cap
- caps on the energy offer prices for individual generators (which constrain the clearing prices for energy)
- additional, administratively determined "shortage pricing" which is added to the prices that would otherwise result from generators' offers to "enhance system reliability by attracting resources to respond to the shortage"[8]
- resulting energy prices that can be US$14,000/MWh.[9]

3.3. The National Electricity Market

The NEM is generally considered by most commentators to be an energy-only market. By international standards it has a relatively high market price cap of $15,500/MWh (FY2023), set at a level which is estimated will allow the

[7] Crampton & Soft, The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem, 2006.

[8] https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/shortage-pricing-fact-sheet.ashx%20(2014)

[9] https://www.pjm.com/-/media/committees-groups/committees/mc/2021/20210322-webinar/20210322-item-08-imm-report.ashx#:~:text=There%20is%20no%20price%20cap%20for%20PJM%20LMP.&text=a%20load%20shed%20or%20voltage%20reduction%20emergency.&text=A.,cost%20is%20%2450%20per%20MWh; https://www.pjm.com/markets-and-operations/energy/energy-offer-verification.

reliability standard to be satisfied.[10] The AEMC's Reliability Panel (the Panel) has recently recommended annual increases to the market price cap, to $21,500/MWh by July 2027.[11] This suggests that a missing money problem could arise in an energy-only market with the market price cap set at its existing level. Either the introduction of a capacity market and/or changing the market price cap from its current level appears required to satisfy the reliability standard in the near future.

However, the term energy-*only* market is not strictly accurate as applied to the NEM. There are of features of the NEM's design that are consistent with a capacity market or capacity mechanism:

- As noted above, the NEM has a decentralised capacity market via the contract market.
- AEMO enters into contracts for the provision of generation and demand response capacity via the reliability emergency reserve trader (RERT) mechanism. In effect, this is a capacity market, although by design it is limited in scope and size. Revenue through the RERT is very low compared to the energy market's turnover.
- The Retailer Reliability Obligation (RRO) creates obligations on retailers to acquire regulated quantities of certain types of financial contracts under certain circumstances.

[10] National Electricity Rules, 3.9.3A(f).

[11] Reliability Panel, 2022 Review of the reliability standard and settings, Final report, 1 September 2022.

4. A THEORETICAL ASSESSMENT OF DOUBLE-DIPPING

A number of commentators[12] have suggest that the market price cap in the NEM's energy market should be lowered upon the introduction of a capacity market. The key concern appears to be that retaining the high energy market price cap will result in a high revenue stream for generators which are then not offset in the capacity market (and vice versa) resulting in generators being paid twice for the capacity they provide: once through the energy market and again through the capacity market. In turn, this will result in high prices for consumers.

This argument is not further elaborated on in any of the submissions received by the ESB in response to its recent high-level design consultation paper.[13] While it is difficult to be sure, it seems possible that this argument may be being made because internationally, and in the WEM, capacity markets are – or were – accompanied by energy markets with low market price caps or offer caps. That is, proponents of the double-dipping argument may consider that low market price caps are a feature of well-designed capacity markets internationally and in the WEM, and so this design should be replicated in the NEM.

The merits of this argument are discussed below.

4.1. Offering behaviour of market participants

This section discusses the offering behaviour of market participants given their incentives. It starts from the simplest case of perfect competition in a single market. It then builds on this by introducing the concept of by-products, first in the case of a perfectly competitive market, and then in the case of imperfect competition.

4.1.1. Single product – perfect competition

In perfectly competitive markets (for any goods or services) which have a single clearing price, the profit maximising behaviour for market participants is to offer to sell at a price equal to the cost imposed on the seller of producing an additional unit of the good or service. This is known as offering at "marginal cost". The reason for this is simple:

- Offering at a price lower than marginal cost risks selling at that price, resulting in a loss.
- Offering at a price higher than marginal cost risks not selling the good/service because a competitor with a lower offer makes the sale instead. Taking this risk comes with no benefit in a perfectly competitive market, because there is no prospect of raising the clearing price of the market.

4.1.2. By-products – perfect competition

More generally, this argument can be extended to the case when two or more goods are by-products of one another. In this case, the profit maximising behaviour of a market participant in a perfectly competitive market is to offer to sell at a price equal to the cost imposed on the seller in the production of the good, *net* of the additional revenue expected to be received from the sale of the by-product (and vice versa). That is, the profit maximising behaviour is to offer at a price equal to marginal costs net marginal revenues. Again, the reason for this is simple:

- Offering at a price lower than marginal costs net marginal revenues received from the sale of the by-product risks selling at a loss, because the collective revenue received from the sale of both products is less than the cost of producing them.

[12] For example: Aluminium Council and CSR Limited.

[13] Available here: https://www.energy.gov.au/government-priorities/energy-ministers/priorities/national-electricity-market-reforms/post-2025-market-design/capacity-mechanism/post-2025-market-design-capacity-mechanism-high-level-design-consultation-paper-june-2022

- Offering at a price higher than the marginal costs net marginal revenues received from the sale of the by-product risks a competitor making the sale instead, with no prospect of raising the clearing price in a perfectly competitive market.

4.1.3. Imperfectly competitive markets

No market is perfectly competitive. In practice due to imperfect competition, where there are two or more goods that are by-products of one another, the profit maximising behaviour of a supplier who is not fully hedged is to offer at a price somewhat higher than marginal costs net of marginal revenues from the sale of the by-product. Due to imperfect competition, the suppliers are no longer necessarily price takers and by offering above marginal costs net marginal revenues there is the prospect of raising the clearing price of the market and making the sale at this higher clearing price.

In determining their offer price, a supplier seeks the optimal trade-off between higher prices and lower quantities which maximise their overall profits. The incentive of any individual supplier to offer at a price higher than marginal costs net of marginal revenues is constrained both by the prospect that high prices will diminish demand, and by the offers of other suppliers, who themselves are attempting to profit maximise making the same trade-off between price and quantity. In highly – but imperfectly – competitive markets, the incentive of a supplier to offer at a price far higher than marginal costs net of marginal revenues is substantially constrained, because of the high – but not guaranteed – likelihood that some other supplier will under-cut their offer price them and make the sale instead. In less competitive markets, the constraint is less substantial, and so the gap between net marginal costs and offers (and prices) can be expected to be greater.

Regardless, profit maximising offers are *based on* net marginal costs, not gross marginal costs – even if the offers are not *equal to* net marginal costs due to imperfect competition. Not offering on this basis would fail to adequately consider the likely offer prices of competitors who would be basing their offers on net marginal costs, leading to a sub-optimal trade-off for the market participant between price and quantity, and less profitable overall outcomes.

For now, the discussion will proceed on this basis of assumed perfect competition because it is a convenient – if extreme – benchmark to facilitate explanation. That is, we will assume that in order to maximise their profits, suppliers offer at exactly marginal costs net of marginal revenues received in by-product markets. In practice, offers will be somewhat more than this, depending on how competitive the market is. We return to discussing whether market power may affect our analysis in section 5.4.

4.2. An example of offers reflecting marginal costs net of marginal revenues

Consider, by analogy, the case the wood-plank market and the sawdust market. Sawdust is a by-product of producing wood-planks (and vice-versa).

If we had auctions with a single clearing price for each of the wood-plank and sawdust markets, then the offer prices made by wood-plank manufacturers would factor not only the additional cost of producing an additional wood-plank, but also the expected additional revenue to be received from the additional sawdust sold in the sawdust market (and vice versa).

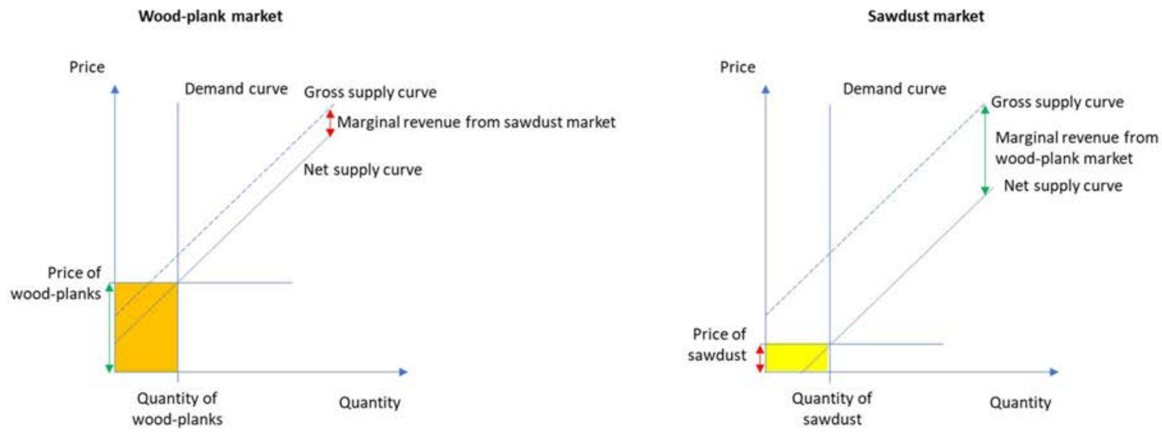
In these markets, the price for sawdust is low in comparison to the price of wood-planks. Consequently, the offer price of wood-planks would only be adjusted downwards slightly to account for the expected small amount of additional revenue to be received from sales of additional sawdust.

While it is common-sense to think of sawdust as the by-product of wood-planks, this discussion works in reverse. The expected price of wood-planks is relatively high in comparison to the price of sawdust, meaning that the offer price of sawdust is adjusted down considerably to account for the expected large amount of additional revenue to be received from the sale of additional wood-planks.

The offer prices in both markets are a function of the expected additional revenues to be received in the other.

These markets are represented diagrammatically below:

Figure 4.1: By-product markets



For simplicity:

- Demand is assumed to be inelastic to price (represented by a vertical demand curve).
- The demand for wood-planks and sawdust are equal to one another, and each unit of wood-planks produced also produces one unit of sawdust (and vice versa).

In both diagrams, the dotted upward sloping line is the *gross* supply curve for each product. It represents the marginal cost of producing both of the products, not taking into account the revenue generated from the sale of the other product.

On the lefthand diagram, in the wood-plank market, the supply curve is adjusted downwards to reflect the marginal cost of producing the wood-panels *net* of the additional revenue expected to be received from the sawdust market (represented by the solid upward sloping line). By producing one more unit of wood-planks, the producer can also sell one more unit of sawdust, and so receive additional revenue in the sawdust market equal to the unit price of sawdust. As a result, the adjustment to the supply curve in the lefthand diagram is equal to the price of the sawdust in the righthand diagram (represented by the red arrows, which are the same length).

Equivalently, on the righthand diagram, in the sawdust market, the supply curve is adjusted downwards to reflect the marginal cost of producing the sawdust net of the additional revenue expected to be received from the sale of additional wood-planks. Similarly, the sized of the downward adjustment, represented by the green arrow, is the same as the price of wood-planks.

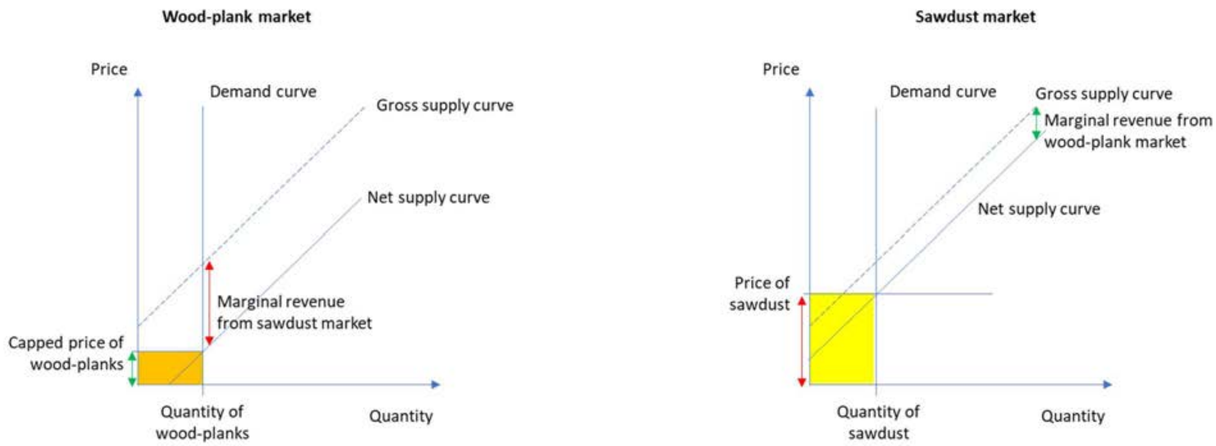
Note that the lefthand diagram and the righthand diagram should not be read sequentially. The outcomes of the sawdust market are a function of the outcomes in the wood-plank market and vice versa, and the explanation above is equally valid had we started with the righthand diagram.

Now let us consider what would happen if regulations were introduced to cap the maximum price for wood-planks at a price such that, absent changes in the sawdust market, there would be a shortfall in the quantity of wood-planks compared to that demanded.

To avoid this shortfall in production, further regulations have been created to allow the government to purchase sawdust in sufficient quantities and at sufficient prices to ensure that there is no shortage in the wood-plank market.

This is represented diagrammatically below:

Figure 4.2: Capped priced by-product markets



The capped price of wood-planks reduces the revenue expected to be received from the sale of an additional wood-plank, decreasing the gap between the gross supply curve and the net supply curve in the sawdust market (green arrows). This increases the price in the sawdust market, which increases the gap between the gross supply curve and the net supply curve in the wood-plank market (red arrows).

The following outcomes are observed:

- The introduction of the price cap does not affect the quantities of wood-planks or the quantities of sawdust produced and consumed.
- The revenue received by the producers in the wood-plank market is equal to the orange box, and the revenue received by the (same) producers in the sawdust market is equal to the yellow box. The total revenue received by the producers is therefore equal to the sum of the orange and yellow boxes.
- The introduction of price cap:
  - changes the proportion of the total revenue recovered via each market, but
  - does not change the total revenue received. Ie, the sum of the orange and yellow boxes is unchanged.[14]

4.3. The theory as applied to capacity and energy market

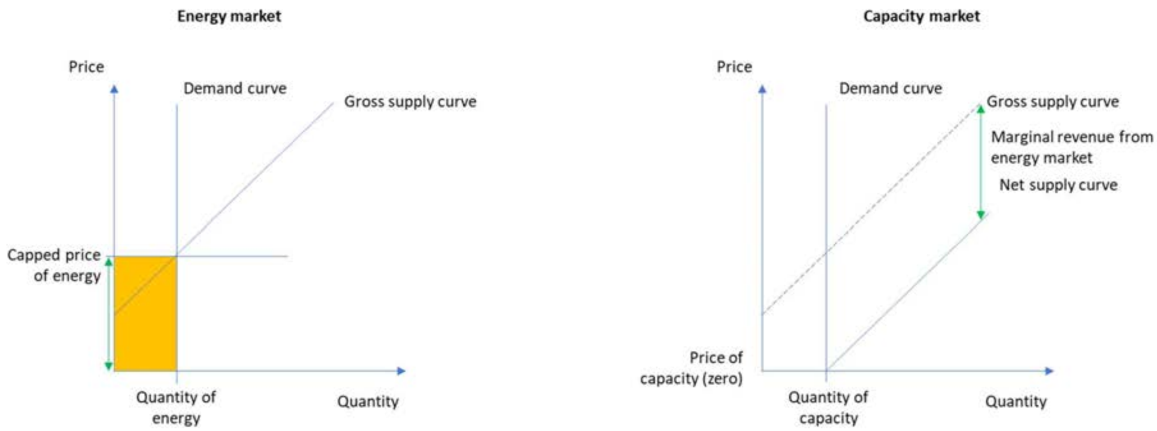
This example is analogous to the energy and capacity markets.

In the existing energy-only market design, the market price cap is set at a price such the expected marginal revenue received from the energy market is sufficiently high that the clearing price for capacity (in a hypothetical capacity market) is zero while meeting 99.998% of the demand over time (ie, consistent with the Reliability Standard). Capacity is provided – for free – as a by-product of the energy market.[15] This is shown in the diagram below.

[14] This result is demonstrated mathematically in appendix A, including the more general case where one additional unit of one product results in a different additional quantity of the other project.

[15] The by-product analogy is not quite perfect, but is nevertheless a useful explanatory tool. Wood-planks and the capacity to make wood-planks would be a more precise analogy than wood-planks and sawdust. Furthermore, the services provided by capacity are often considered to a “public good” or “non-rivalrous” (ie, users cannot be barred from accessing the services even if they don’t pay for them).

Figure 4.3: Energy only market

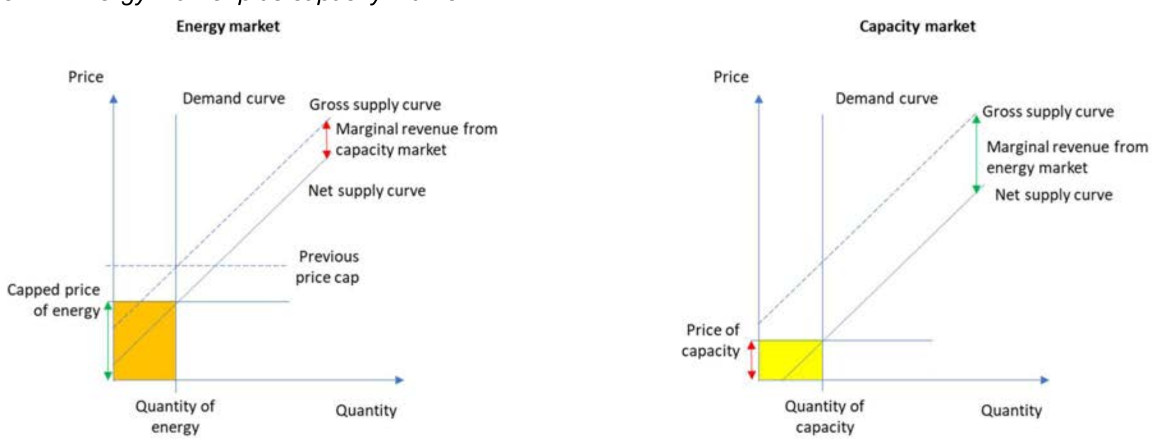


In Figure 4.3, the lefthand side represents the sum, over many dispatch intervals, of the outcomes in the energy market. That is, the vertical axis represents an amalgamation of prices over time, the horizonal axis represents an amalgamation of quantities over time, and the orange box represents the sum of revenues expected to be received in the energy market over time, given the market price cap.

The market price cap of energy is sufficiently high that the expected additional revenue from the energy market (the green arrows) offsets the gross supply curve in the capacity market such that the demand for capacity is met without separately paying for it. As such, under the energy-only market design with a sufficiently high market price cap, a capacity market is redundant, all of the revenue is recovered via the energy market, and the reliability standard is met.

Below, we show what happens if the market price cap is reduced:

Figure 4.4: Energy market plus capacity market



Capping the price of energy lower has the effect of reducing the marginal revenue from the energy market (green arrows) and so decreases the gap between the gross and net supply curves in the capacity market such that the clearing price in the capacity market is positive. This in turn introduces the gap between the gross and net supply curves in the energy market. The total quantity of energy and capacity delivered to the market, and the total revenue received by the generators, are all unchanged. The lowering of the price cap and the introduction of the capacity market moves revenue between markets, without affecting the total revenue received (unless moving revenue between markets in and of itself reduces costs – discussed in section 5.5).

Double-dipping – whereby generators would not reflect the revenues and prices in the capacity market in their offers in the energy market and vice versa - would therefore not be expected to occur upon the introduction of a capacity market.

This analysis also explains why relatively low energy market price caps are – or were – commonly associated with capacity markets. It is not the case that low market price caps are a desirable feature of energy markets given a capacity market. Instead, it is that in theory there is no need for a capacity market if the market price cap is high enough. The direction of causation is that the low market price cap creates the missing money problem that then needs to be addressed via a capacity market. Low market price caps justify capacity markets, not the other way around.

5. ASSUMPTIONS AND FURTHER ANALYSIS

Key assumptions and further discussion relating to this analysis are explored below. This chapter discusses:

- how the fact that the capacity market is not run at the same time as the energy market affects the analysis
- the impact of price responsive demand
- what happens if the market price cap is set incorrectly in the energy-only market
- competition and market power concerns
- what happens if costs (most notably the cost of capital) change as a result of moving revenue between the energy and capacity markets by changing the market price cap.

5.1. Simultaneous outcomes in both markets

In the wood-plank and sawdust market, both markets are cleared simultaneously. This will not be the case upon the introduction of a capacity market to sit alongside an energy market. Instead, the capacity market will clear first (perhaps annually), with offers in the capacity market based on *expected* cumulative future revenues and costs in the energy market which clears every five minutes (as well as on expected future revenues from future capacity market auctions).

If there are no penalties for non-delivery of capacity, then the outcomes in the capacity market do not affect the bidding behaviour of generators in the energy market; the outcomes in the capacity market are sunk. The market price cap has the effect of suppressing the incentives for generators to deliver energy at times of system stress – either because the opportunity cost of not delivering energy is lower, or because the actual cost of making derivative contract payments is lower. To address this problem in a capacity market design, administrative penalties are required to recreate the incentivises to delivery energy at times of system stress, effectively replicating the incentives that would exist were it not for the market price cap or making them even stronger than would otherwise be the case to if the market price cap is not set at the marginal value of lost load.

Ensuring these administrative incentives are appropriate may be challenging, and getting the penalties wrong can result in many problems:

- Incorrect incentives for generators to generate at times of system stress (for example, despite having fuel costs less than the market price cap it may nevertheless be profit maximising for the generator to take necessary (but not super-critical) planned outages, or to not hurry back from such an outage if the system became stressed).
- Incorrect incentives for energy constrained generators (or storage) to efficiently conserve energy.

In turn, these incorrect incentives can flow through to inefficient investment and disinvestment decision-making in generation and storage.

These problems do not arise if the market price cap is sufficiently high that generators have a strong incentive to deliver energy in real time.

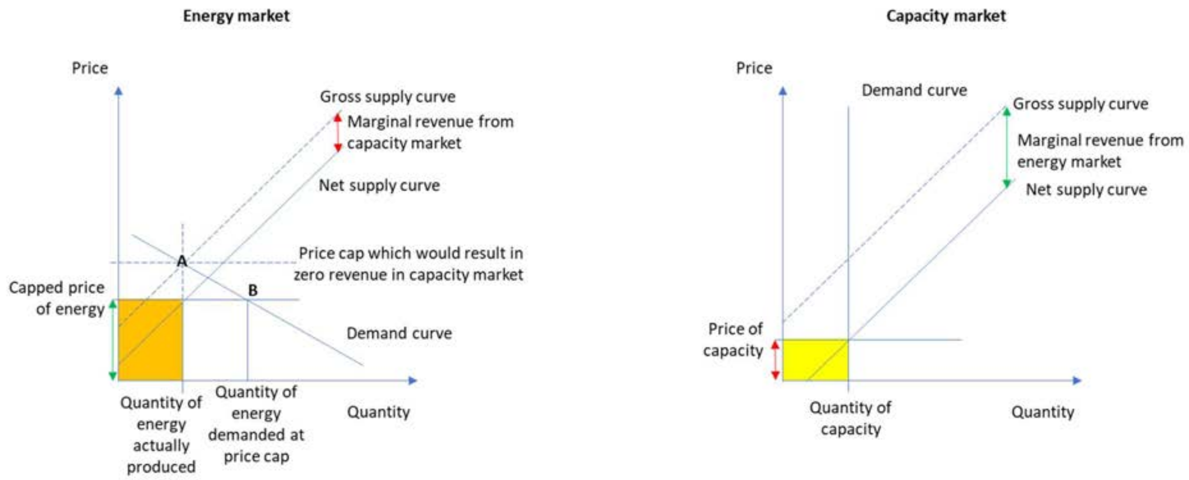
5.2. Inelastic demand

A key assumption in the discussion above is that demand for energy is inelastic to changes the in the price of energy.

In practice, demand is somewhat elastic, particularly when prices are at or near a (high) market price cap.

The effect of elastic demand is illustrated in the diagram below:

Figure 5.1: Inelastic demand



The elastic demand is represented by the downward sloping demand curve in the lefthand diagram. The slope on the demand curve is exaggerated for ease of illustration. It intersects the gross supply curve where the market price cap would have been were the market price cap set at a level sufficient to meet the reliability standard and for there to be zero revenue in the capacity market (point A), but slopes downwards from there such that at the new, lower capped price of energy, demand is higher (point B). The supply of energy does not meet demand, and additional administrative load shedding is required. The lower energy price cap has had the effect of exacerbating reliability problems by incentivising additional demand at times of system stress, requiring additional load shedding.

To address this problem, capacity markets participants include consumers of electricity. As with supply side (where the price cap is too low to induce sufficient supply to meet demand absent an administrative penalty), these demand side participants also require an administrative penalty for not reducing their demand at times of system stress – replicating the incentives that would otherwise have arisen in an energy-only market but were curtailed by a lower price cap.

As with the supply side, ensuring these administrative penalties are appropriately tuned to induce an efficient response may be challenging, and getting it wrong can result in excessive demand response (at a cost to overall economic efficiency), involuntary high value load shedding instead of voluntary, lower value demand response, and incentives to charge storage even when the system is under stress. Again, as with the supply-side these can in turn flow through to inefficient investment decisions in equipment to facilitate demand response and storage assets.

The cumulative effect of introducing the lower price cap is therefore as follows:

- Reducing the revenue received via the energy market but increasing the revenue via the capacity market, such that the total revenues between the two markets are unchanged (unless moving revenue between markets in and of itself reduces costs – discussed in section 5.5).
- The need via the capacity market to contract with, and then administratively penalise, generators who do not provide energy at times of system stress, because the penalty that would otherwise have naturally existed for not providing energy at these times – the high price – has been reduced.
- The need via the capacity market to contract with consumers to consume less than they otherwise would given the supressed price, and to administratively penalise these contracted consumers who continue to consume consistent with those suppressed prices.

5.3. THE MPC BEING SET AT THE APPROPRIATE LEVEL UNDER THE ENERGY ONLY MARKET

As shown in Figure 4.3, under the energy-only market design, the MPC is intended to be set at a price such that the clearing price in the capacity market is zero while delivering an expected level of reliability consistent with the reliability standard. This makes the centralised capacity market redundant – hence the name "energy-only" market.

If the market price cap is below that required to deliver the reliability standard, and there is no capacity market, then reliability will be lower than the reliability standard (although prices will also be lower). Assuming that the reliability standard is set at a level which appropriately trades of the marginal cost of load shedding with the addition cost to avoid that load shedding, a level of reliability lower than the reliability standard would be inefficient.

Conversely, if the market price cap is set higher than this level, and there is inelastic demand, then additional generator capacity above and beyond that required to meet the reliability standard would be expected to enter the market. This would increase prices for consumers – but also increases the level of reliability that consumers enjoy to a level above the reliability standard. Again, this would be inefficient if the optimal trade-off between reliability and price is at the reliability standard.

The ESB identifies this problem in its most recent consultation paper.[16]

A possible solution to this problem is to set the MPC at the lower end of the estimates for reliability consistent with the reliability standard, and introduce a (small, in revenue terms) capacity market to make up for any missing money created by this conservative approach to setting the MPC.

For example, IES were engaged by the the Panel as part of the Panel's Reliability Standard and Settings Review to estimate the appropriate MPC absent a capacity market for the period July 2025 to June 2028. Its findings indicate that the appropriate market price cap would be in the range of \$21,000/MWh to a minimum of \$29,000/MWh (depending, among other things, on the level of the cumulative price threshold (CPT)).[17] The lower of this figure could be used and a capacity market introduced. If the appropriate MPC was \$25k/MWh, then the relatively small amount of missing money arising from the price cap being slightly too low would be recovered through the capacity market. If, on the other hand, the MPC was set at \$29k/MWh and in practice the appropriate MPC was \$25k/MWh then the capacity market would be expected to clear at zero, inefficiently large amounts of capacity would be installed into the system via the signals provided by the energy market, resulting in higher than efficient level of reliability and price.

However, this approach of conservatively setting the MPC and introducing a capacity market does not fully resolve the problem. The challenge that faced administrators in determining the appropriate MPC to induce reliability equal to the reliability standard is conceptually similar to the challenge that will face administrators in determining the appropriate amount of capacity to directly procure via the capacity market, and designing the various incentives and penalties in the capacity market to replicate a higher MPC.

Regardless, the first-best solution to this problem – whether it manifests in the administrative challenge of designing a capacity market or the administrative challenge of determining the appropriate MPC to induce the efficient level of capacity via the energy-only market – is a well-functioning two-sided market where the demand side is responsive to energy prices. As recognised by the Panel (2007), if this was the case, there would be no need for a reliability standard, a market price cap, a capacity market, or involuntary load shedding. Like in other markets, consumers would simply choose to consume or not consume in response to real-time prices:

> *"in most commodity markets the price for the commodity in question is decided at any moment in time through the buyers (the demand side) and sellers (the supply side) agreeing on a price at which to transact. In effect, consumers signal the value they place on supply – and this provides a price signal to the market, at times when a shortfall in supply is forecast, to drive investment in new supply. In such markets, there is*

[16] ESB, Capacity mechanism - high level design paper, June 2022, p.13.

[17] IES, Reliability Standard and Settings Review 2022 – Modelling Report, Final Report, p.107.

no need for a minimum level of supply to be determined by a central body, because it is possible for the consumers themselves to signal clearly at what price they are willing to curtail demand."

…

"In the absence of wide-scale demand-side participation the price of electricity is predominantly set by the supply side, with some limited DSR [demand side response] from (typically) large users who have the ability to indicate their price sensitivity and curtail load without impacting other consumers (for example, large industrial consumers that have direct connection to the transmission network). For this reason, and because electricity supply is considered an essential service, it is necessary for electricity systems to have some form of reliability standard to signal the minimum expected level of reliability, and reliability mechanisms within the market design that are aimed at delivering the level of supply capacity needed to meet that standard."

Of course, there are challenges to increasing the levels of demand response in electricity markets. It requires real-time pricing information (noting that energy prices change every 5 minutes), adjusting consumption in response to these prices, and sophisticated metering. None of this was feasible for most consumers in the mid-1990s when the NEM was originally being designed, creating the need for a reliability standards and settings, including the market price cap.

However, we consider it reasonable that technological change since then has reduced these barriers – and will continue to do so into the future. The internet allows for the instant flow of pricing information; automation of devices allows for consumption to be managed without the need for manual tinkering of demand or mass blackouts of entire suburbs; and smart meters have been rolled out to many. This would suggest that raising – not lowering – the market price cap is the appropriate direction of travel, because the need for the price cap, and the downsides of setting the cap too high, appear to be diminishing over time. Compared to the start of the NEM, there is now less need for the regulators to be making one-size-fits-all decisions on consumers' behalf about the level of reliability they desire.

5.4. Competition and market power concerns

Throughout the preceding discussion, we have assumed the markets are perfectly competitive, such that generators offer at a price exactly equal to their marginal costs net of marginal revenues.

As discussed in section 4, the profit maximising behaviour of uncontracted market participants in an imperfectly competitive market is to offer somewhat above marginal costs net of marginal revenues (ie, above net marginal costs).

Market power in the capacity market

Reducing the market price cap in the energy market below that required for the reliability standard to be met while the capacity market clears at zero will reduce expected revenues from the energy market and so increase net marginal costs in the capacity market, for the reasons provided throughout this report. Because profit maximising offers are based on net marginal costs, reducing the energy market price cap would increase capacity market offers and prices even in a substantially uncompetitive capacity market. Reducing the market price cap in the *energy* market therefore does not appear to be an appropriate approach to addressing market power in the *capacity* market – to the extent that market power in the capacity market is a concern.

Market power in the energy market

As discussed above, the expected revenue from the energy market would be factored into the offers made in the capacity market. If there was an expectation of higher prices in the energy market due to scarcity or market power in that market then the capacity market clearing price would be lower, and vice versa. Indeed, it is the expectation of scarcity in the energy-only market design that drives the capacity price to zero, rendering a separate capacity market unnecessary.

Of course, expectations may prove to be wrong, and generators may in the fullness of time enjoy higher prices in the energy market than were expected at the time the capacity market cleared. Assuming they are uncontracted they would enjoy profits higher than would otherwise be the case. But this is not a sign "double-dipping", nor a justification for a low market price cap in the energy market. It simply reflects the normal functioning of a market given that the future is uncertain. And, of course, prices in the energy market could be lower than expected.

5.5. Changes to the cost of capital

One of the key arguments put forward by the ESB in support of introducing a capacity market is as follows.[18]

Revenues derived from the energy market are risky, because of:

- inherent uncertainties facing the sector (eg, uncertainty about demand for electricity)
- an inadequately functioning contract market to manage risk, particularly over the long term, because typically contract lengths are substantially shorter than the life of a generation project
- the prospect of government intervention curtailing profits should energy prices rise, despite the possibility of high energy prices being an important driver of investment in an energy-only market.

Given these risks, the cost of capital required to make an investment is relatively high, in turn requiring a relatively high market price cap and relatively high prices for consumers to obtain a given level of reliability. Put another way, it may be rational for generator to discount future revenues earned via the energy market to a level lower than their probability weighted average.

Conceivably, the prospect of government intervention could be such that no market price cap is high enough to stimulate sufficient investment to meet the reliability standard. The explicit market price cap may be irrelevant because prospective investors perceive a far lower implicit price cap that would be introduced should prices rise. This implicit lower price cap may deter the necessary levels of investment to meet the reliability standard regardless of the explicit market price cap.

A capacity market may address these concerns by reducing the risk faced by investors, reducing the cost of capital, and so – *all else unaffected* – reducing prices or increasing reliability for consumers. Investors no longer need to rely on uncertain energy and contract market prices, but instead can obtain greater revenue certainty by entering longer-term contracts with a central agency such as the system operator.

It appears implicit in the ESB's argument in support of a capacity market that the market price cap should be lower than it would otherwise need to be to maintain sufficient levels of reliability via an energy-only market. As noted throughout this report, reducing the energy market price cap has the effect of increasing the revenues that flow through the capacity market. An overall reduction in the cost of capital might therefore be achieved by lowering the market price cap and increasing the relative size of the capacity market.

Importantly in the context of the topic of this report, this is not an argument in favour of lowering the market price cap to avoid "double dipping", but instead to reduce the overall cost of capital. If the overall cost of capital is reduced, then this would be reflected in a lowering of the gross costs to provide capacity and energy. Generators

[18] ESB, Capacity mechanism - high level design paper, June 2022, section 3.2.

acting in a profit maximising manner would still offset this (lower) gross cost by the marginal revenue expected to be received in the energy market when bidding in the capacity market.[19]

However, there are crucial trade-offs with reducing the market price cap to increase the proportion of revenue flowing through the capacity market and hence reduce the overall cost of capital for investors.

Firstly, by reducing the risk for investors, much of the risk has been transferred onto consumers. Lower prices, should they arise, are enjoyed by consumers at the expense of higher risk for consumers. Like investors, consumers are also risk averse, and so it is not clear that the risk-price trade-off is in their long-term interest.

Secondly, investment decisions are increasingly made by central agencies such as the system operator that do not bear their financial consequences of those decisions. Indeed, central agencies may have incentives to deliver inefficiently high levels of reliability, increasing total system costs and prices for consumers. This effect may in practice exceed the reduction in prices arising from reducing the cost of capital, leading to an overall increase in prices for consumers.

In contrast, in an energy-only market with a sufficiently high market price cap and absent the risk of ad hoc intervention by governments, investors face strong financial signals to make investments that are consistent with delivering the reliability standard (assuming the price cap is set at the right level). If, despite these incentives, inefficiently high levels of investment and reliability arise, prices *decrease*, with investors – not consumers – bearing the financial consequences.

Thirdly, a lower market price cap can lead to numerous operational inefficiencies which in turn may also flow through to investment inefficiencies – both of which exacerbate reliability problems and increase costs. Elaborating on the discussion throughout section 5, a low market price cap reduces incentives for:

- all generators to generate at times of power system stress
- generators with very high fuel costs to generate at times of power system stress, if the cap is below the fuel costs of the generators
- energy-limited generators to efficiently ration their energy stocks
- investment in flexible (eg ramping) generators
- consumers to voluntarily reduce their demand at times of power system stress or when energy stocks are low, and to make investments in demand response capabilities
- storage to charge and conservatively discharge, and reduces the incentives on storage investment which profits from the inter-temporal spread of low and high prices.

While a full analysis of the effects of the administrative pricing events of June 2022 are beyond the scope of this report, this event appears an excellent example of many of the issues listed above. The administered price cap of $300/MWh is far lower than the existing market price cap, but in principle these problems all arise – to a greater or lesser extent – if the energy market price cap is lower than that required to deliver against the reliability standard without the need for a capacity market.

The Panel appears to agree that there are benefits of a relatively high market price cap, even were a capacity mechanism to be introduced for the purpose of reducing the cost of capital. It noted that:

> *"The Panel has considered the potential for complementary reliability tools and mechanisms to limit the extent to which future MPC/CPT increases are needed to address investment needs in a transitioning*

[19] The effect of a positive cost of capital is to discount future costs and revenues. Consequently, a change to the cost of capital could be considered to change the gross supply curve or, equivalently, a change to the amount by which the gross supply curve is offset by to account for the discounted future revenue from the energy market. Either way, profit maximising offers will still be based on net marginal costs.

power system. The Panel considers a market with very strong scarcity price signals can also include other complementary measures to provide a higher degree of certainty in supporting investments that are critical for maintaining reliability in a transitioning power system In particular, when those complementary measures are needed to support investment while also avoiding MPCs which create systemic risk challenges and approach the VCR [value of consumer reliability]. The Panel notes, however, that any complementary mechanisms should be efficiently coordinated with market operation and price signals. The presence of such mechanisms should and ideally would enhance the scope and performance of a market rather than replace it and promote the long term interests of consumers."

6. EVIDENCE TO SUPPORT THE THEORY

The previous chapters provided a theoretical explanation of the relationship between market price caps, capacity markets and energy markets.

Real-world evidence in support of these arguments is provided below.

6.1. Essential system services

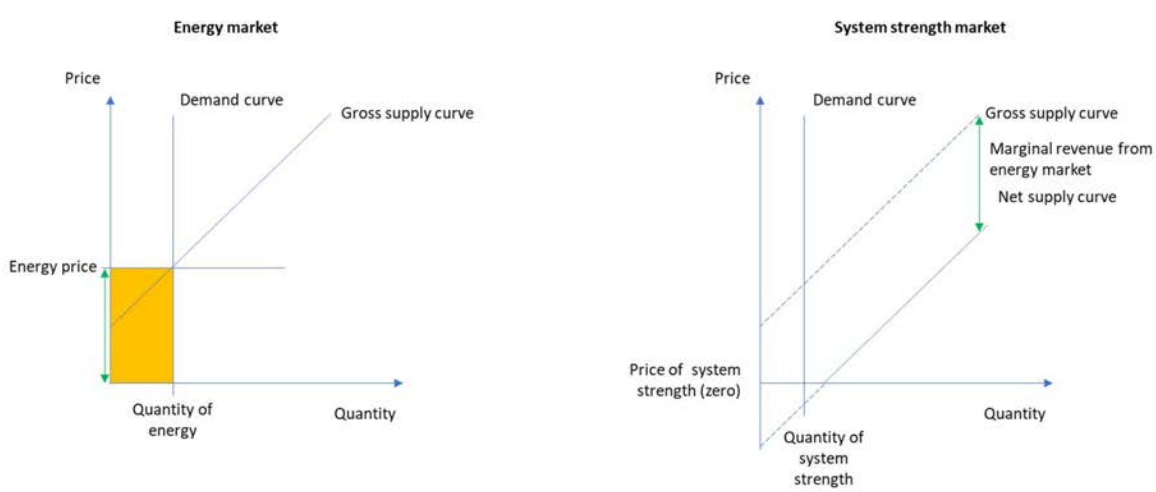
The AEMC and ESB are currently undertaking a program of reforms to deliver frequency control, system strength and inertia services required to keep electricity supply secure.[20]

The underlying rationale for these reforms – as explained by the ESB and AEMC – is that:

> *"The NEM has traditionally relied on thermal generators to provide the frequency control, inertia and system strength required to ensure system security. Because inertia and system strength were historically provided as a by-product of energy generation, the NEM has not had mechanisms to signal the need for, or pay for, these services until recently. With the current proportion of non-synchronous generation in the NEM, those services can be short of requirements at times and AEMO has needed to intervene in the market to maintain security"*[21]

The ESB and AEMC have therefore implicitly used the arguments throughout this report to justify why various essential system services markets were unnecessary until recently but have now become necessary. The gross marginal cost of supplying the required quantity of system strength (for example) to the system is clearly not zero, and yet historically the efficient price of system strength has been zero (as indicated in the quote above). This is because the marginal revenue from the sale of energy and other ancillary services to the market is netted off from gross system strength supply curve, in exactly the same way that the marginal revenue from the sale of energy is netting off from the capacity supply curve (and vice versa), resulting in a price of zero:

Figure 6.1: Historic energy and system strength markets



More recently, the increased prevalence of non-synchronous generators (such as wind and solar) means that system strength is no longer provided in sufficient quantities as a by-product of energy production. Regulations or markets are required to ensure that demand for system strength is met.

[20] https://esb-post2025-market-design.aemc.gov.au/ (Essential System Services 'tab'); https://www.aemc.gov.au/our-work/our-priorities.

[21] https://esb-post2025-market-design.aemc.gov.au/32572/1599208730-final-p2025-market-design-consultation-paper.pdf, p. 55

Moreover, the Panel's draft estimate for the market price cap required to deliver the reliability standard without a capacity market already explicitly employs the arguments throughout this report. The NEM's energy-only market is already accompanied by ancillary services markets. In modelling the appropriate market price cap, the Panel's consultants, IES, nets off expected revenue from the frequency control ancillary services (FCAS) markets from the capital costs of generators, noting:

> *"The amount of revenues earned from the energy and FCAS spot markets impacts the balance of generation costs that needs to be recovered from the reliability settings during the USE events."*[22]

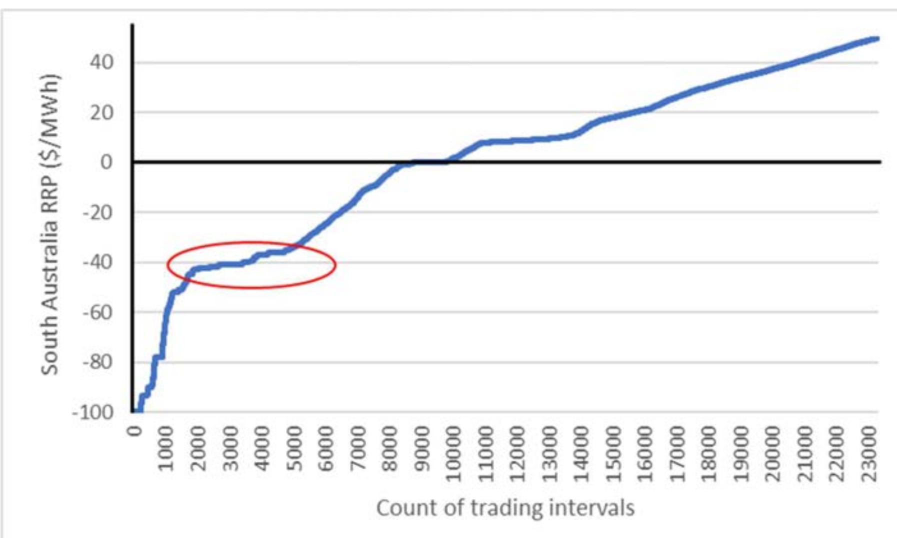
IES argues that historically high FCAS revenues are unlikely to continue (due to a lessening of the supply-demand tightness in FCAS markets), resulting in the need for a higher market price cap in the energy market to meet the reliability standard than would otherwise be the case.

The ESB, the AEMC, the Panel, and its consultants have already employed the arguments used throughout this report in multiple other contexts and should continue to do so when considering the appropriate level for the market price cap upon the introduction of a capacity market.

6.2. Large-scale generation certificates

Figure 6.2 below shows the cumulative trading interval prices in South Australia between -$100/MWh and +$50/MWh for calendar year 2021, arranged in ascending order.[23] As marked in the red circle, many prices are between approximately -$45/MWh and -$35/MWh. In fact, nearly 8% of all trading intervals in 2021 in South Australia settled between these prices.

Figure 6.2: Cumulative prices in South Australia, 2021



Certain renewable generators in the NEM are entitled to create large-scale generation certificates (LGC). One LGC can be created per megawatt hour (MWh) of eligible electricity generated. These certificates can then be sold, providing an additional revenue stream for eligible renewable generators (or means that the company that owns the

[22] IES, Reliability Standard and Settings Review 2022 – Modelling Report, final draft report, p. 118.

[23] This is approximately 23,000 trading intervals, or about 60% of the total trading intervals in 2021. The other approximately 40% of trading intervals had prices below -$100/MWh or above +$50/MWh are excluded from the figure for ease of presentation. Note that the introduction of five-minute settlement on 1 October 2022 increased the number of trading intervals per hour by a factor of six.

generator avoids an obligation to purchase an LGC). LGC spot prices change based on market conditions, but prices in 2021 were between about $32 and $45 per certificate (ie, per MWh of eligible energy generated).[24]

Generators in the NEM appear to net off the marginal revenue received from the LGC market when making offers in the energy market, as evidenced by energy prices in the NEM that are often approximately equal to the net of the marginal short run cost of variable renewable generation (ie, approximately $0/MWh) and the marginal revenue received from the LGC market (ie, between about $32/MWh and $45/MWh). If the market clears at around -35/MWh, then zero short run marginal cost renewable generators still make a profit, despite the negative energy market price, due to the marginal revenue received via the LGC market. Offering energy significantly above these prices by ignoring marginal revenues from the LGC market would not be profit maximising, because the generator would expect to be undercut by a profit maximising competitor that is taking into account the marginal revenues it receives from the LGC market when making its offer into the electricity market.

6.3. Price caps in capacity markets internationally

In most capacity markets internationally, market power is a concern in those markets and measures have been taken to address it.

For example, in PJM's capacity market, demand for capacity "is determined administratively based on a design objective to procure sufficient capacity for maintaining resource adequacy in all locations while mitigating price volatility **and susceptibility to market power abuse**" [our emphasis added].[25] This demand curve creates a capped price in the *capacity* market – a seemingly more direct way to address market power concerns in that market than capping the energy price.

Interestingly for the purpose of this report, in PJM, Great Britain, New York, New England and elsewhere the administratively determined demand for capacity is set as a function of its estimate of the *net* cost of new entry (net-CONE) – ie, an estimate of the cost of new entry less expected revenue from energy and ancillary services markets. Indeed, the ESB, drawing upon these designs internationally, was also considering using a multiple of net-CONE to determine the NEM's capacity market price cap.[26] Clearly, if the market price cap in the *energy* market was lower, then the cost of new entry net of the revenue from the energy market would be higher, in turn increasing the capped price in the *capacity* market (and vice versa). The concept of double dipping does not appear to be of concern in the capacity market design of these markets, where netting expected revenues from the energy market is an important feature in the design of the capacity market.

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[24] https://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/qcmr/march-quarter-2022/Large-scale-generation-certificates-(LGCs).aspx

[25] https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx

[26] ESB, Capacity mechanism - high level design paper, June 2022, figure 15, pp. 44-45.

7. QUANTATIVE ANALYSIS

7.1. Simplified model

We have developed a simple excel-based model to illustrate the theory provided in this report. Given this intent, the model is highly stylised and does not attempt to accurately represent real conditions in the NEM. Consequently, the model results in financial (revenue, capital expenditure, operational expenditure) and physical outcomes (capacity, dispatch, unserved energy) that are incomparable to the NEM.

In this model, users input:

- two separate demand forecasts over six dispatch intervals, and the probability of each demand forecast. Inputting a relatively high demand but a low probability demand forecast approximates the real-world conditions of the NEM but avoids the need for many thousands of dispatch intervals to be modelled
- generator variable costs for producing energy ($/MWh), the cost of generator expansions ($/MW) and the generators' current capacity, for six generators
- the energy market price cap
- the target level of unserved energy (for example, 0.002% of the total probability weighted energy demanded).

From these inputs, the model:

1. calculates the total quantity and combination of generation capacity that meets the target level of unserved energy at lowest total system cost
2. given this combination of capacity, selects the least variable cost combination of generators to meet demand in a given dispatch interval, and determines the price in that interval to equal:
    - the marginal generator's variable cost where capacity exceeds demand, or,
    - the market price cap where capacity is less than demand and there is load shedding
3. determines the revenues and profits for each generator arising from the energy market only in each dispatch interval, given the prices and quantities
4. determines the probability weighted total profits arising from the energy market only (ie, energy market revenues less energy and capacity expansion costs) across all the dispatch intervals for each generator
5. determines the $/MW offers that each generator would make in the capacity market, such that the total revenue received from capacity and energy markets combined is equal to at least zero
    - If the probability weighted total profit from the energy market alone is positive for a particular generator, then the offer it makes in the capacity market is zero.
    - If the probability weighted total profit from the energy market for a particular generator is negative (ie, absent a capacity payment the generator would make a loss), then offers in the capacity market are positive.
6. determines the price in the capacity market to equal the marginal capacity offer given the total demand for capacity determined at step 1, and the revenue received for each generator for the provision of capacity at that price
7. determines the overall probability weighted average revenue and profit of each of the generators, combining the energy market and capacity market revenues and all costs.

Key assumptions include:

- only six dispatch intervals, unlike the thousands of dispatch intervals that are typically modelled in full market modelling. These six dispatch intervals, plus the capacity market, represent the entire market (ie, the model does not account for revenue from dispatch intervals beyond these six, nor future capacity market revenue)
- no time value of money (ie, any capacity expansions occur immediately prior to the start of the first interval). Zero cost of capital and so zero discounting of energy market revenue to account for uncertainty in that revenue stream
- simple generator cost functions: no start up costs, no ramping constraints no minimum generation, no planned or unplanned outages, simple availability profiles (ie, always available to 100% of capacity), no fixed costs (eg, relating to operations and maintenance)
- offers equal to net marginal costs in the energy market and capacity markets
- no demand response
- instantaneous capacity expansion
- no lumpiness to capacity expansions (ie, capacity can be added in infinitely small increments)
- no divestment costs (eg, existing capacity with high variable costs can be removed at zero cost)
- a single region with no transmission constraints.

While these simplifications are wholly inadequate to estimate the *absolute* level of revenue for the generators for a given market price cap, we consider them appropriate to demonstrate whether there is a *change* in total revenue for the generators arising from a *change* in the market price cap.

Consistent with the theory outlined in this report, the model shows that for any combination of inputs, providing the market price cap is at or below the level required for there to be a clearing price of zero in the capacity market, then changing the market price does not affect any physical or financial outcomes. Ie, it does not affect the:

- combination of generators which are dispatched
- total unserved energy
- total revenue received by the generators
- total profit of the generators.

It does, however, change the proportion of revenue received in the capacity and energy only markets.

To be clear, this model assumes the theory as part of its design, and so is intended to be a demonstration of the theory. It does not provide evidence in support of the theory per se.

7.2. Market modelling

We have also been engaged to provide advice on how one would model in a less styled way the effect of changing the market price cap on overall revenues given the introduction of a capacity market.

The key design feature that should be included in such a model is that generators net off marginal revenues from marginal costs when making offers in either the energy or capacity market – consistent with the theory outlined in this report and the approach taken in our simplified model. Netting marginal revenues is a common approach used in energy market modelling. As noted in section 5.3, IES nets the marginal revenue expected to be received from FCAS markets when modelling the market price cap absent a capacity market (although we note that IES assumes FCAS revenue exogenously, as opposed to co-optimising the FCAS and energy markets to determine the FCAS revenue endogenously).

The model should ideally co-optimise both the capacity market and energy market – with the outcomes of the one informing the other, and vice versa.

More generally, most of the simplifications that we have made in our model could be removed, but in many cases doing so would be unlikely to demonstrate the effect in question any more clearly. That is, while addressing most of the simplifications would result in better estimate of the *absolute* revenues of generators, it would be unlikely to affect the result that physical or financial outcomes are unchanged by changing the market price cap.

One example of a simplification which will affect this result is the discount rate (assumed to be zero in our simplified model for both capacity market and energy market revenue). As noted in section 5.5, a core rationale of the ESB for introducing a capacity market is the believe that revenue received via the capacity market is less risky, and therefore would be discounted by investors less substantially than revenue received through the energy market. If so, reducing the market price cap has the effect of increasing revenue via the capacity market, and so reducing the overall cost of capital and the overall revenues received by generators (ignoring the various other effects of lowering the market price cap could have).

Estimating the size of this effect requires an assumption regarding the relative discount rates of revenue in the energy market and capacity market. A larger gap in the assumed discount rates would result in a greater reduction in the total revenue received by generators for a given reduction in the market price cap. Given these assumptions, a model that more faithfully represents the NEM would be able to estimate the dollar impact.

Caution would nevertheless be required in interpreting the results. Not only are they predicated on the assumed relative discount rates applied to the energy and capacity market revenues, they also ignore the possible negative consequences of a lower market price cap outlined throughout this report. For example, we consider it extremely challenging, if not impossible, to meaningfully model the effect of non-financial incentivises on the procurement decisions of the system operating in the capacity market.

Appendix A

This appendix mathematically demonstrates that the sum of revenue received across two by-product markets is unchanged as a result of introducing a market price cap in one of the markets.

This analysis assumes:

- demand is inelastic
- there is perfect competition
- there is no change in cost (such as the cost of capital) from receiving revenue via either market.

The revenue received across both markets collectively for all suppliers is the sum of the products of the prices and quantities in these markets:

$$\text{Total revenue} = P_1 \times Q_1 + P_2 \times Q_2 \qquad [1]$$

Where:

- P_1 is the price of product 1 (eg, woodplanks)
- P_2 is the price of product 2 (eg, sawdust)
- Q_1 is the quantity of product 1
- Q_2 is the quantity of product 2

Define a factor, F, which is the ratio between the quantities of the two products produced on the margin. That is, if the marginal production of product 1 produces two additional units of product 2, then F is 2.

$$Q_1 \times F = Q_2 \qquad [2]$$

The marginal revenue received from selling product 2 as a consequence of producing one more unit of product 1 is:

$$\text{Marginal\_revenue}_1 = P_2 \times F \qquad [3]$$

Where:

- $\text{Marginal\_revenue}_1$ is the marginal revenue received in market 1 from selling in market 2.

Assuming perfect competition, the price of product 1 is determined as the market-wide marginal cost of producing an extra unit of product 1 and F extra units of product 2, less the marginal revenue received from selling F units of product 2.

$$P_1 = C - \text{Marginal\_revenue}_1$$

$$P_1 = C - P_2 \times F \qquad [4]$$

Where:

- C is the market-wide marginal cost of producing one unit of product 1 and F units of product 2.

Inserting equations [2] and [4] into equation [1]:

$$\text{Total Revenue} = (C - P_2 \times F) \times Q_2 / F + P_2 \times Q_2$$

$$\text{Total Revenue} = C \times Q_2 \; / F = C \times Q_1 \qquad [5]$$

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