Matt Garbutt
Energy Security Board

19th October 2020

By Email to: info@esb.org.au

Dear Mr Garbutt,

P2025 Market Design Consultation Paper

The Australian Energy Council (the "**AEC**") welcomes the opportunity to make a submission in response to the Energy Security Board's ("**ESB**'s") P2025 Market Design Consultation Paper ("**the Paper**").

The AEC is the industry body representing 21 electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. These businesses collectively generate the overwhelming majority of electricity in Australia, sell gas and electricity to over ten million homes and businesses, and are major investors in renewable energy generation.

On such a broad consultation as this, the AEC's wide membership inevitably encompasses a wide range of views. These will be articulated in individual submissions. The AEC's submission however reflects a generalist perspective and is developed consistent with our core philosophy that always seeks to maximise the role of competitive, risk-taking investment in generation and customer engagement.

Summary

The ESB is to be congratulated for undertaking such an extremely wide-ranging review, and, in recent months engaging effectively with stakeholders. The AEC supports the Market Design Initiative ("**MDI**") structure, which categorises the main issues very well, and, for the most part, the AEC concurs with the descriptions of the issues and challenges of each MDI.

The AEC particularly agrees with the narrative of the Essential System Services ("**ESS**") of "missing markets". It is in this MDI that market failure has unarguably already occurred and is thus in most pressing need of attention. Whilst the issues in ESS are very technically complex and not widely understood, they are also crucial to the security of the system and of relatively low cost to rectify.

The AEC embraces the concept of engaging the demand side more within the market processes as desired by the two-sided market MDI. However the proposals are at this stage less well developed than other MDIs and the AEC cautions that proposals introduced towards that worthy objective do not attempt to drive consumers and retailers into deep engagement before they are technologically or culturally prepared.

In integrating distributed energy resources ("**DER**"), steps need to be taken to deviate from what has historically been a network-centric framework. Whilst there may be certain services where a distributor led technical solution is more cost effective for the overall system, the AEC holds a strong preference towards markets that compensate customers for the services provided. The regulatory framework governing DER integration must, as its first priority, empower consumers with the choice to utilise and optimise their own DER assets.

The question of the appropriate capacity remuneration mechanism is a perennial question for electricity markets. The present design has clearly achieved its reliability expectations to date and performed more efficiently for the consumer than some other designs implemented elsewhere. Nevertheless the technical changes in the industry – some of which make the challenge of achieving reliability more difficult – would justify re-considering the market design with an empirical perspective.

However the more concerning circumstantial issue for the market design is external expectations of a reliability level well beyond the economic optimum combined with a range of disorderly government interventions. These factors would make it highly challenging for any market design to achieve its objectives. Before undertaking any major redesign, the ESB needs to clearly understand governments' objectives in reliability and under what circumstances they would be prepared to allow the market to self-converge. Without such a compact arranged in advance, the ESB may find that it implements an apparently robust market design, only to discover that is equally undermined by external interventions.

The scheduling and ahead markets MDI remains unclear about whether it is responding to an intrinsic scheduling problem, or whether it is simply observing issues that are being appropriately resolved in the other MDIs, particularly in ESS and Two-sided markets. The AEC provided a detailed consultancy report on this matter in mid-2020 and is pleased to note that the ESB has positively evolved its thinking since then by removing a mandatory physical ahead market option. The AEC has re-engaged expert advice on the options presented in the Paper which is attached to this submission. Whilst the two optional ahead market mechanisms are less burdensome, the advice doubts whether they are workable and that their development could prove to be an unsuccessful distraction of resources from other parts of the ESB's work.

The AEC recognises that much deeper transmission development has been recommended for the National Electricity Market ("**NEM**"). Transmission can play a major role in a reliable, secure and low-carbon transition, however it is not the only way of achieving these ends. Ultimately it should be developed where its benefits demonstrably exceeds its costs, but not elsewhere. The AEC largely supports the current regime for planning, justifying and regulating transmission and considers that every project, including example interconnectors and Renewable Energy Zones ("**REZ**s") should always be subject to pure cost-benefit analysis. Unexpected inflation in the costs of transmission equipment is undermining the quality of that analysis, and the AEC recommends investigating whether regulatory approaches can be used to improve planning estimates.

The review will complete with numerous recommendations for implementation. The AEC considers these should be made through the standard Rule Change process which is able to account for consultation already undertaken.

Conclusion

The AEC recognises the gargantuan task facing the ESB in assessing numerous disparate views, identifying possible unknowns and likely external forces, and setting a path for a future market which encourages competition, is technically feasible, has appropriate risk levels, and is overall economically efficient.

To this end it will be important for proposed changes to be implemented incrementally, to the extent possible, assessed for their economic efficiency by rigorous processes such as those used by the Australian Energy Market Commission ("**AEMC**"), and telegraphed in good time so stakeholders can adequately prepare.

The AEC's comments, and responses to the Paper's questions, can be found in the attached submission which deals with each MDI in turn. We have incorporated our consultant's response to the Scheduling and Ahead Markets MDI in the Appendix.

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MDI – A RESOURCE ADEQUACY MECHANISMS

Reliability

The question of confidence in the fundamental market design to deliver resource adequacy is a perennial point of contention in all electricity markets and is quite naturally a key consideration for this review. In the 1990s, the NEM chose the relatively unstructured approach of an energy-only market, enabled by a relatively high market price-cap. This design and price-cap never had an unrealistic ambition in the elimination of supply shortfall, but instead targeted an economically defensible reliability standard of 99.998% of energy served.

In the AEC's mind, this reliability standard, market design and price-cap has served the consumer well to date. It has delivered beyond the standard's expectations of reliability, and done this more efficiently than outcomes observed in other markets.

Whilst the AEC considers the 99.998% reliability standard best serves the customer, there is perennial government anxiety about forecasts of any risk of supply shortfall – even when these risks are entirely appropriate and poorly understood. In that regard, the NEM has already partially deviated from the design by:

- employing a reliability safety-net, the Reliability and Emergency Reserve Trader ("**RERT**"); and,
- obliging retailers and large customers to commit to financial products adequate to meet their expected peak load, the Retail Reliability Obligation ("**RRO**").

Whether or not economically defensible, if successful in sating government concerns, such deviations are of much lower cost than alternatives. They were also developed through a careful design process by independent agencies leveraging industry input. Thus, unintended consequences were largely avoided.

More worrying however are signs that governments remain ever-unsated by such concessions, and desire to impose ever-more distorting mechanisms in an apparent impossible ambition of eliminating all risk. In particular the AEC cites:

- The interim reliability standard of 99.9994%
- Implementation of a 3-year RERT mechanism
- Removal of the 3-year trigger for the RRO
- A New South Wales "N-2" supply surplus objective
- Threats to directly invest in 1000MW of additional supply beyond the current reliability outlook (that meets the permanent standard)

None of the above developments emerged from what could be seen described as a thoughtful, independent nor consultative process. The ESB's primary goal in the resource adequacy context should in fact be external to the market: explaining the economics of reliability to government and resisting such distortions at their source. If successful in that regard, the ESB has much greater chance of achieving its functions with respect to delivering an efficient market design.

If unsuccessful, it must be recognised that a market which is designed to deliver the most economically efficient trade-off of reliability and cost to the customer is by definition incompatible with government expectations of something quite different. If the ESB has accepted the latter, then contemplating significant market re-design is unavoidable. However, before it embarks on this, it needs to first obtain a clear and unified understanding from governments as to what reliability outcomes they expect a new market to achieve.

If this understanding is not first achieved, the ESB may impose a disruptive market re-design, only to discover these distortions continue unabated and the re-design fails in its objectives.

Industry transformation

The other great challenge to the NEM's current design is the dramatic change in the way we generate and consume electricity.

Clearly a supply side dominated by variable zero marginal cost sources was not a factor in the 1990s and rightly causes questioning of a design developed at that time. Integrating these sources into the market creates many challenges, but they are not, in a theoretical sense at least, incompatible with an energy-only market so long as it has the right market settings and investor confidence with respect to external distortions. And the challenges that arise due to variable generation seem common to all market designs.

On the other hand, technological developments in the demand-side create an opportunity for a price responsive demand-side for energy to finally emerge. This also did not exist in the 1990s, but has the effect of relieving some of the challenges described above.

Whilst not dismissing in any way the valid concerns about the market's investibility and the need to investigate alternatives, the AEC's view is that the most pressing responses to the industry transformation are correctly being dealt with by the ESB in other MDIs, being:

- resolving the "Missing Markets" problem in ESS; and,
- integrating a responsive demand-side into the market.

Section 4: Paper Questions

1. *Do you have views on whether the current resource adequacy mechanisms within the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition?*

The AEC supports the paper's descriptions of the risks to the investment cycle created by a combination of the inherent challenges of a system with high variable renewable energy along with the ongoing threat of government intervention.

The current market design has performed well to date but faces challenges with the difficult combination of more conservative reliability expectations, variable zero marginal cost generation and ad-hoc government interventions.

Faced with such factors, the current market would anticipate the raising of price caps. The AEC is not opposed to this, but doing so brings its own risks and should be done progressively under reliability panel advice.

It is nevertheless prudent to investigate more fundamental alternatives to the energy-only market. However, we should also be realistic that all market design examples employed around the world are challenged by the same three factors described above and none present a perfect solution.

Regardless of whether any alternative resource adequacy mechanisms are pursued, the AEC cautions against any reductions to the existing price caps which are a key part of the functioning of the real-time energy market.

2. *Do you have views on whether the short-term signals provided by an operating reserve mechanism or market would provide adequate incentives to deliver the amount and type of investment needed for a Post-2025 NEM in a timely manner? What impact could an operating reserve have on financial markets? What are the benefits of this approach? What are the costs and risks?*

The AEC supports development of the operating reserve mechanism.

Whilst the operating reserve clearly has benefit for (and was originally designed for) short-term market balancing requirements, the AEC recognises its potential to boost the investment signal and supports this aspect as a relatively incremental change to the market design compared to other resource adequacy mechanisms ("**RAM**") options.

However to perform this investment function, the design needs to recognise it explicitly: e.g. first determine what level of additional reliability or assurance beyond that implied by the price cap the ESB wants to achieve.

Its success in achieving an investment boost will of course be dependent on the considerable design issues yet to be engaged with:

- Identifying services that meet the power system's need, in terms of:
    - short-term responsiveness and flexibility,
    - location in the network; and,
    - reliable and sustainable capacity.
- How the services are funded and how the revenue stream can be hedged.

We note the salutary lesson of the Western Australia Wholesale Electricity Market ("**WEM**") whose capacity market criteria was structured such that for a time entrants were dominated by emergency-style demand-resources for which there was a low degree of confidence in their responsiveness, reliability and sustainability. Furthermore, many were resources with extremely high marginal costs – possibly higher than the NEM's price caps. If these became dominant in an operating reserve, then it would likely fail in the provision of additional investment support in reliable and sustainable reserves.

3. *Do you have views on whether the signals provided by an expanded RRO based on financial contracts or a decentralised capacity market would provide the type of incentives participants need to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What are the benefits of this approach? What are the costs and risks?*

The AEC is interested in the results of this investigation into an expanded RRO. However much more development and explanation is required before the AEC could support its implementation.

The history of the existing non-physical RRO invokes caution in the AEC regarding an expansion of its role. This was originally intended to be a relatively light-touch assurance mechanism to ensure, when forecasts consistently showed insufficient investment to meet the reliability standard, that retailers were prudently hedging. However the compliance burden has proved onerous for retailers. At the same time, its design has been undermined by changing the triggering mechanism reliability target.

During investigation of a physical RRO, the AEC would recommend:

- Retiring the existing contractual RRO requirements.

Not inhibiting retail competition, i.e. accredited physical positions should remain tradeable between retailers.

- Not changing the existing spot market arrangements and risks, e.g. the price caps.
- Not imposing any distortionary "must-run" style obligations upon accredited plant.
- Accrediting existing firm conventional generation sources unless clear evidence has emerged that it is no longer capable of fulfilling that role.

The AEC suggests before it concludes a position on the physical RRO, the ESB consider carefully the AER's work in relation to accrediting the reliability value of generation, storage and demand-side for the financial RRO. This is a challenging and contentious exercise but was undertaken for the financial RRO only after the design was committed.

4. *Do you have views on how an operating reserve mechanism and/or expanded RRO would impact the need for and use of RERT and the interim reliability reserve if they were introduced into the NEM? What adjustments to the RERT and/or interim reliability reserve may need to be made so that they are complementary and not contradictory or duplicative?*

The AEC considers that the requirements for reliability should be built into the market mechanism such that all firm supply and demand response is treated equally and responds as much as possible to one market signal. It is of great concern that the emergency safety net of the RERT is being ever more relied upon instead of the market, which implies that:

- reserves are being under-rewarded by the market; and,
- reserves are being drawn away from the market.

The AEC accepts that it is unlikely governments will accept abolition of the RERT, however it is hoped that with the implementation of a new RAM we could see the RERT return to its original intent of a last-resort safety net. This would imply that it should return to a nine-month lead time in order to stop drawing reserves from the market itself, including any new RAM.

Reserves double-dipping between RERT and a new RAM should be prohibited, as it is for the energy market currently.

5. *Do you have views on how RAMs (current or future) can better be integrated into broader jurisdictional policy priorities and programs? Should jurisdictions reflect broader policy priorities through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve?*

Given the increased interconnectedness of the NEM, the AEC supports a national framework for delivering the NEM's reliability, with its settings overseen independently via the Reliability Panel. Jurisdictions' reasonable interests in maintaining reliability within their state should be articulated through their formal participation in the NEM's governance and they should not have a role in specifying technical variations to market design that would apply jurisdictionally.

A key purpose of developing a RAM is to give jurisdictions comfort that an efficient level of reliability will be procured in the NEM and thereby discourage state derogations. Whilst this risk cannot be eliminated, the AEC is very cautious about installing within a RAM an explicit jurisdictional lever which will tempt such behaviour.

Nevertheless, the AEC accepts there is a rationale for providing it as a lesser evil than the sorts of interventions experienced presently. If such a mechanism is introduced, it should be developed in such a way to give, say, 5 years notice of effect, and that spill over effects into other jurisdictions are minimised.

MDI – B AGEING THERMAL GENERATION STRATEGY

Section 5: Paper Questions

1. *Have we correctly identified the cost, reliability and security risks to consumers from the transition away from thermal generation?*

The AEC notes and supports the ESB's evolution of this MDI into a form of stress-test to apply the other MDIs – particularly RAMs and ESS - rather than something requiring a specific market design of itself. The AEC suggests market forces are the best way to allow the closures of ageing plant to work through. We should not attempt to immunise the market, as customers' interests are best served by allowing natural signals that underpin an investment response.

To that extent, the AEC does not support proposals that attempt to engage with this issue separately to the overall market design or attempt to engineer a different closure characteristic than would emerge as a result of market value and plant age.

2. *Are these risks likely to be material, particularly those relating to consumer costs?*

This question seems rhetorical because with over a dozen multi-billion dollar plants reaching end of life over the next three decades, the costs will unavoidably be large, and ultimately paid by consumers, no matter how a power sector is structured.

The AEC's view is that the consumer is ultimately best off however in allowing markets to fully influence closure decisions and, in turn, to allow closures to fully influence markets.

Closure decisions are impacted by both the technical operability of the plant alongside the value created by the market. We should ensure that plants get the full value that they are bringing to the power system, for example by pricing ESS, but otherwise not try to pre-determine their closure decisions. By giving generators freedom to respond to market signals they can retain the ability to optimise their closure at the best time for the system as a whole – and avoid locking in decisions unnecessarily early when circumstances are always fluid.

There are risks of catastrophic plant failures in all power systems, and this is in no way unique to ageing plant. The reliability calculations incorporate a risk of plant failure, and the safety net mechanisms are intentionally designed to respond to such eventualities. Prices may well rise upon such an event, but this is an intentional and natural outcome. The price rise could, for example, cause other closure plans to adjust in a beneficial way, and we should be loath to introduce any unnecessary inflexibilities upon such an efficient market response.

3. *Are there additional or alternate market design approaches that will ensure the transition away from thermal generation is least cost to consumers?*

As discussed above, the RAMs and ESS MDIs should be developed cognisant of expected plant closures, but no market designs should be adopted specifically to address the natural transition in generation technology.

4. *Should the ESB consider and develop any of the options outlined in this section further?*

The AEC is concerned that the Grattan proposal would:

- Be an expensive burden on the industry which could be counter-productive by causing a sudden deterioration in the financial circumstances of an ageing generator.
- Distort efficient dispatch through the bond accumulation levy.
- Inhibit flexibility in the closure decision which is necessary to respond to market events.

"Must-run" style arrangements with closing thermal plants can easily distort the market by suppressing the very signals necessary for an efficient and orderly transition. This should only be considered as a last resort in the most extreme security/reliability (not price) circumstances and achieved through the existing Australian Energy Market Operator ("**AEMO**") intervention approaches that are designed to minimise price distortion. In practice a retiring coal plant is very unlikely to be a practical source of emergency reserve.

Contingent scenario planning for early closures already occurs by AEMO within the Integrated System Plan ("**ISP**") and Electricity Statement of Opportunities ("**ESOO**"). This is appropriate. Jurisdictions should be encouraged to engage with the issue only through AEMO's functions and discouraged from developing separate activities.

MDI – C ESSENTIAL SYSTEM SERVICES

The AEC considers this the most pressing MDI and the only MDI where there is already indisputable evidence of market failure. The AEC concurs strongly with the ESB's "missing markets" narrative and would say this issue alone lies at the core of the two hundred directions a year occurring presently in the NEM.

Designing the missing markets is highly technically complex, requiring a rare combination of electrical engineering and micro-economic expertise. Fortunately, however, once solved, ultimately the services should be procurable at a relatively low cost (compared to, say, building new firm generation capacity). This combination of complexity and low value has caused it to often be de-prioritised in market design considerations. Yet these reasons are exactly why it should be prioritised.

The two hundred directions are often cited as evidence of the need for dramatic energy market reform, however in the AEC's opinion these could almost all have been avoided with a generator system service mechanism – market based or contractual – for South Australian system strength. It is to the NEM's great discredit that this repeated intervention was permitted to exist for over two years without such a service emerging.

With respect to frequency control performance, the AEC has long accepted the need to improve this, but disagreed with the mandatory provision of narrow-deadband primary response as per the recently implemented rule[1]. In the AEC's mind this rule runs directionally counter to the missing markets narrative: that we can no longer rely on essential system services being provided for free as an inherent feature of traditional generators. Instead they must be market-valued.

Fortunately the mandatory rule is sunsetted, but there is a significant risk that insufficient action will be taken in the meantime and there will be no option but to ultimately roll-over the sunset. In that regard the AEC has developed an options paper which winnows down the options for primary frequency control down to two possible "pathways".[2] The AEC feels the detailed design can be led by the AEMC through a current rule change[3], but a clear indication in the P2025 review of a need to resolve this before the sunset is most welcome.

The AEC broadly agrees with the Paper's characterisation of the issues and the supporting work from FTI Consulting. The AEC is not concerned about a proliferation of mechanisms – attempting to over-simplify ESS' inherent complexity has unintended consequences. However the actual mechanisms should be approached pragmatically. Given their relatively low value and urgency, FTI's laudable aspirations for purchasing efficiency through competitive spot markets and sloping demand curves, may need moderating.

Section 6: Paper Questions

1. *What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating reserve procurement for resource adequacy? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment needed for a Post-2025 NEM? What are the benefits of this approach? What are the costs and risks?*

As discussed in Section 4, the AEC supports further work on the Operating Reserve.
The AEC feels the Operating Reserve could deliver two objectives:

[1] See submission https://www.aemc.gov.au/sites/default/files/2019-11/Rule%20Change%20SubmissionERC0274%20-%20Australian%20Energy%20Council%20-%2020191031.PDF
[2] https://www.energycouncil.com.au/media/690570/20200922-aec-pfr-submission.pdf
[3] https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

- provides greater observable confidence that supply/demand can be met on an hour-to-hour basis, particularly subject to the new shocks of swings in RE; and,
- provides an additional investment incentive in firm reserves than would be provided alone by the energy market (subject to existing price caps).

Although the Operating Reserve was originally conceived for the short-term issue, with the second emerging as something of a by-product, the AEC recommends that both objectives now be given equal prominence in the design. The AEC sees no tension between the objectives, however all features of the design should be tested against each objective.

To be useful as a short-term support, it will be necessary to ensure the reserves can be accessed quickly, say in 30 minutes, and physical features of the reserves, for example their network access and ability to sustain output for an extended period, will need to be understood and levels of acceptability set.

The costs and risks will need to be analysed further to confirm that this option is genuinely at the minimalist end of reform options. As discussed in Section 4, the issues of who pays and how easily this can be hedged are critical to the success of the design.

The sloping demand curve concept proposed for other ESS does not appear applicable here. The demand curve for unscheduled demand is administratively determined at the market price cap and it would be inappropriate to set other effective energy price caps through the operating reserve.

2. *What are your views about developing Fast Frequency Response with FCAS and developing a demand curve for Frequency Response? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements. What additional mechanisms might be needed to foster investment for a Post-2025 NEM. What are the benefits of this approach? What are the costs and risks?*

The AEC supports further work on the fast frequency response ("**FFR**") along the lines of the Infigen rule change and has submitted to that effect[4]. The AEC is attracted to its design being largely an additional timeframe to the existing well understood three Frequency Control Ancillary Service ("**FCAS**") contingency markets, and its design being a replication of them. That design would see it naturally co-optimised with the energy market and all the other FCASs.

The AEC submitted that if, unlike the other FCAS, inertial response is not excluded from the response calculation, this FFR FCAS might be able to deliver, in one spot market, a signal for both inertia and FFR. High inertia generators would then be likely to self-commit in response to high prices in an FFR FCAS, even when energy prices are low.

The AEC also supports the Reliability Panel being tasked with the role of determining the desired outcomes through the frequency operating standards, and that the level of FFR procured should match this.

Whilst not disagreeing with the logic of a sloping demand curve, the AEC notes that this is not used in any of the existing FCASs presently. If FFR design is introduced as a replication to the other services, and is co-optimised with them and energy, it is not clear how a sloping demand curve could be applied purely to it. It may be better to implement the FFR initially through a direct replication of the other services and to subsequently contemplate options for a sloping demand curve to apply broadly across all FCAS.

If a sloping demand curve is to be used, the AEC again recommends that the Reliability Panel determines its broad parameters.

[4] https://www.energycouncil.com.au/media/18903/20200813-aec-system-services-final.pdf

3. *What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?*

The AEC broadly concurs with the ESB's desire to move from mandatory/directed provision, to structured provision and ultimately to spot markets. The AEC supports moving away from the first, but as noted in the consultation paper, the AEC considers that a shift toward spot market procurement requires consideration of the trade-offs in complexity.

The peculiarities of system strength: technical complexity, localisation, non-fungibility, non-linear dispatch and network substitutability mean that a spot market is unlikely to ever be a sensible goal. For this ESS, focus should be on efficient provision through a combination of monopoly network (e.g. TransGrid rule change) and long-term structured contracts of competitive providers with either networks or AEMO. With respect to the choice between either a Transmission Network Service Provider ("**TNSP**") or AEMO, the ESB should consider carefully the issue of asset neutrality. Again, the AEC considers the Reliability Panel should determine preferred System Strength standards – and it is noted the TransGrid rule change proposes a role for them.

For inertia, as noted previously, it may be possible for this to be procured by way of an FFR FCAS. This could provide a sufficient incentive to encourage adequate self-commitment to maintain inertia security, but would in any case remain supported by AEMO's power of direction should that prove inadequate.

If the ESB however concludes that it prefers to distinguish inertia from FFR, then structured provision between AEMO and generators would seem to be the appropriate approach for acquiring inertia initially. This would enable AEMO to centrally commit and cover the costs of high-inertia generators operating during low energy prices. AEMO is already successfully doing effectively this to obtain voltage control at light loads in Victoria presently.

4. *Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?*

The AEC is not necessarily comfortable with the suggestions of providing greater unilateral flexibilities to AEMO and networks in the development of ESS. These parties are naturally accountable for system security outcomes and not for cost.

A recurring theme in the AEC's recommendations is for decision making power on the desired security outcomes to rest with the Reliability Panel and its broad independent membership and necessary grasp of the trade-offs between cost and security.

The AEC also considers that, following the high-level directions provided in the P2025 process, the actual procurement design return to reviews and rule changes run by the AEMC.

As an example of the AEC's concerns, it notes that developments in the area of Primary Frequency Response since 2018 were not led by these two parties. The result – a mandatory uncompensated obligation without any outcome objectives – is in the AEC's opinion a very poor outcome, but unsurprising since it was promoted with purely a system security focus and a bias to conventional and non-market solutions. This is an example of the outcomes that can emerge when led by parties purely with accountability for security and uninvolved in investment innovation.

MDI – D SCHEDULING AND AHEAD MECHANISMS

Early in 2020 this MDI presented some complex material from which the industry struggled to fully grasp:

- what shortcomings justified such apparently sweeping changes to the spot market mechanism;
- whether a centralised commitment mechanism and two-pass settlement could produce a cogent result in a NEM context; and,
- whether the perceived shortcomings could be addressed in other ways.

In response, the AEC commissioned expert advice from Creative Energy Consulting[5] ("**CEC1**"), and the AEC is pleased the ESB gave this report deep consideration. CEC1 noted that the purported justification for the sweeping change hinged on the same issue identified in MDI – C, effectively the "missing markets" problem. As discussed in MDI-C, the oft-cited two hundred directions a year could be readily resolved with a contract for South Australian System Strength. In any case, the ESB's (and AEMC's through related rule changes) work on essential system services is now placing due attention to the root cause of the unit commitment problem.

The AEC is pleased to note the ESB has subsequently evolved its thinking. The AEC strongly supports not progressing further work on the mandatory ahead market option.

CEC1 supported development of a Unit Commitment for Security ("**UCS**") mechanism as effectively an AEMO internal decision tool to assist its use of direction where necessary (noting directions should be much less common in future thanks to MDI-C work). CEC1 saw no rule barrier inhibiting AEMO from developing such a tool unilaterally.

The Paper has similarly recommended UCS for development and implementation, however the description appears somewhat more substantial than what was envisaged by CEC1.

The Paper has also recommended two voluntary ahead market options for development. It was not clear to the AEC whether such options were operable, and so Creative Energy Consulting were re-engaged to consider the new proposals in the Paper. That report is attached to this submission ("**CEC2**").

Section 7: Paper Questions

1. *The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?*

See CEC1 and CEC2.

The AEC supports developing the UCS options and the abandonment of the mandatory ahead market option.

It remains unclear how Options two and three would operate, particularly as the services to be traded ahead of time are yet to be designed. These options seem at best premature, but seem likely to ultimately prove unworkable.

The AEC is not opposed to the concept of voluntary ahead trading, but considers work on these options at this time to be an unworthwhile distraction.

[5] https://www.energycouncil.com.au/media/18717/20200630-cec-final-report.pdf

The AEC notes that CEC1 contained significant recommendations to improve the functioning of pre-dispatch within the existing single-pass market and recommends resources currently looking into options two and three be first diverted to that task.

2. *The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?*

Yes, see CEC2.

3. *The difference between actual and forecast residual demand leading up to real time dispatch has been far more stable in the last decade than the difference between actual and forecast prices ($MWh) leading up to real time dispatch. What do you consider the drivers of this may be?*

It is not clear why the ESB considers this metric to be meaningful or even of concern. The ESB has not noted complaints from activate market participants that price forecasts are proving less reliable than they were historically.

Whilst the analysis has made some attempt to exclude residual demand, it has made no meaningful attempt to unpick other possible drivers. It is unreasonable to expect submitters to speculate on causation when presented with such limited information.

If pre-dispatch inaccuracy has grown to a point that it has become a serious impediment to market efficiency, then unpicking the issue in detail would be the first step before considering major reforms such as an ahead market. Instead, ahead designs have been proposed purely from theoretical assumptions, and only at this late stage has some rather simplistic evidence been provided.

MDI – E TWO-SIDED MARKETS

The AEC supports the ESB's objective to further encourage consumer participation, and two-sided markets. Greater consumer engagement has the potential to incentivise innovation, reduce prices, and increase efficiency in the system.

That being said, the AEC consider this MDI lacks clarity when compared against the other MDIs presented in the Consultation Paper. It is unclear how the proposed reforms illustrated in the short, medium and long term roadmap will feed into the overall objective of two-sided markets, including when considered in conjunction with the ongoing development of existing regulatory enhancements currently being undertaken by market bodies and other solutions developed by market participants.

There are both regulatory and non-regulatory barriers to a fully functioning two-sided market at this time. It shouldn't be assumed that a lack of development in demand side markets and consumer engagement in recent years will be mirrored in coming years. Recent technological enhancements have been significant, and ongoing developments will continue to make engagement easier and more beneficial for customers.

In the second half of the last decade, there has been significant efforts to enhance consumer participation in the market. Rule changes have been implemented requiring cost reflective network prices, obligations on participants to publish increased demand side information, and most recently rules have been made to introduce a wholesale demand response mechanism. The benefits of these reforms have not yet been realised for a number of reasons, and further incremental reforms should only be considered when the notable barriers in the existing framework are better understood and mitigated.

Finally, the AEC considers there needs to be greater efforts to quantify the benefits of further reforms at this time. Of particular importance is the question of what levels of participation you need to deliver benefits from intervention over and above incremental market development through competition. The ESB should seek to identify and prioritise reforms that will deliver the greatest benefits, with assessments weighted towards interventions most likely to obtain an adequate level of participation.

Section 8: Paper Questions

1. *What do you consider are the risks and opportunities of moving to a market with a significantly more active demand side over time? How can these risks be best managed?*

There are clearly opportunities from encouraging greater demand side participation over time. But, that is not to say that recent reforms have not sought to enable this already. Certainly, at least for small customers, jurisdictional governments have thwarted efforts to increase demand side activity by developing and regulating barriers that dampen price signals, and seek to ensure 'fairer' outcomes for all. Two sided markets cannot progress without a clear understanding from all stakeholders as to the benefits and risks of reforms.

Naturally there will be trade-offs. Whilst the most efficient outcome would be to make all consumers directly responsible for their impact on the wholesale market, this would clearly diminish the ability for customers who do not wish to engage to that extent to be able to access the services they desire at a price they are willing to pay. In this context, all moves towards a two-sided market must be considered against the spectrum of consumer protections and price efficiency.

There will also likely be different risk appetites between different segments of the market. Large customers already increasingly contract with retailers in a bespoke manner, and the Wholesale Demand Response Mechanism ("**WDRM**") will provide them with further opportunities to engage irrespective of their retail offer. This MDI should seek to better distinguish between the benefits of increasing participation for all customers, versus the benefits for increasing participation for just a subset of customers, such as large customers or customers with DER.

There are additional risks to non-participating consumers if market evolution is limited to enhancing opportunities for third parties and aggregators, at the expense of existing market participants. In recent years there have been multiple efforts to enact change in a manner that seeks to diminish the retailer/customer relationship at all costs, so as to allow consumers to contract with third parties for aspects of their service that benefits them. As an example, proposals such as Multiple Trading Relationships ("**MTR**") sought to enable non-retailers to contract with customers to buy or sell energy deemed non-essential, while the retailer would be required to provide the essential services. While this might be beneficial for the participating customer who is able to reduce their reliance on their retailer by effectively sub-contracting their load, this reduction means a retailer is less able to cross subsidise the costs of delivering the essentiality of energy across their customer base, and the costs for inactive consumers will rise. These risks must be mitigated if we are to seek to enhance demand side participation.

2. *What are the barriers preventing more active demand response and participation in a two-sided market? What are the barriers to participating in the wholesale central dispatch processes?*

There are many barriers in the current market, and potentially further barriers depending on how demand side participation is developed. These barriers are both regulatory and non-regulatory.

As noted above, non-regulatory barriers such as the availability and cost of enabling technology, limitations in the functionality of technology, and the challenges of aggregation due to the diverse range of solutions available have inhibited the development of customer participation to date. These barriers will naturally decline in coming years.

That being said, a number of retailers have been able to offer innovative products within the existing market structures, however it can be difficult to build customer engagement to the point that might be considered a genuine two-way engagement.

The primary regulatory barrier today for small customer participation is the presence of retail price caps. These caps dampen price signals, and the presence of complementary reference pricing further decreases the ability of retailers to offer innovative pricing and products targeted at subsets of the market. These two barriers must be amended if a significantly more active small customer market is desired.

The second regulatory barrier has been the actions taken by jurisdictional governments. It is rational for a jurisdictional government to seek to minimise the impact of change, however, we have seen the overarching desire for no customer to be worse off has resulted in recent reforms failing to reach their potential. For example, cost reflective network pricing ("**CRNP**") was intended to enable retailers to offer products to customers that better reflected their impact on the network – thus providing price signals as to when it was or wasn't efficient to consume energy. The economic theory said that if customers had a visible price signal, then they would choose to consume energy at a more efficient time and reduce pressure on peak demand. This has not eventuated in practice, with Governments appearing to prefer an overall (relatively) higher price, instead of some customers benefiting due to their consumption profile and some paying more.

Additional barriers exist in the insufficient incentives for existing market participants to seek to increase demand-side participation ("**DSP**"). To continue the CRNP example, retailers have minimal incentives to implement more dynamic pricing that reduce overall network costs to their existing customer base, and while retailers have taken steps to offer more dynamic signals that reduce their costs, their primary objective is to provide customer's confidence that they will not be charged more than they are willing to pay. Retail costs are minimised when customers are satisfied with their service offering. Assuming customers are less likely to be satisfied when their price is unexpectedly higher, it is rational for retailers to seek to avoid pushing reforms that increase that risk. National Metering Identifier ("**NMI**") level network pricing is an example of a practical barrier to CRNP that might benefit from an alternative approach. NMI level pricing mean a retailer is unable to aggregate customer demand effectively, limiting its ability to better utilise the network. This barrier might be resolved with reforms to network pricing that enabled retailers to purchase network capacity on behalf of their customers in bulk, and then onsold to individual NMIs in a way that benefited both parties.

Competition should enable customers who wish to benefit from more dynamic pricing to do so, without requiring all retailers to offer all services. The existing lowest common denominator approach increases regulatory costs, and requires existing participants to rebuild systems frequently to ensure that other parties are able to benefit from access to their customer book. This is an inefficient response, and the AEC would welcome approaches through this project to mitigate this outcome. An optimal outcome would enable retailers and existing participants to delay reform implementation until such a time as customers demand it. This would provide opportunities for first-movers to act quickly and create markets, while other providers might opt not to participate until such a time as their customers were leaving them for their competitors.

There are additional barriers caused by the homogenisation of the retail rules, with retailers offering services only to large customers being required to develop systems that comply with small customer regulations 'just in case' a small customer might transfer incorrectly. It would be beneficial for these unnecessary barriers to be resolved prior to a fundamental redesign of the customer to market relationship.

The AEC considers more work needs to be done to better understand the impacts of requiring retailers to participate in forecasting of demand and scheduling load. There are quite significant technical and compliance issues that need to be worked through. Whilst participation in forecasting may be beneficial for some consumers who actively wish to engage in the market, for the vast majority of other consumers, AEMO will be able to better deliver accurate estimates of demand than a retailer would. This might result in the need to enable traders to be able to engage customers and schedule their load, but retaining the obligation on AEMO to continue forecasting the demand of all others. In a sense, a trader might be able to opt out of the existing process where it is beneficial to do so.

Similarly, it is important that a two-sided market does not value demand side and DER differently to generation. For aggregators who are able to schedule the load of their customers, AEMO is able to allocate these resources and lower wholesale costs. Developing mechanisms that enable aggregators to pass benefits from a participant to traders irrespective of their impact in reducing the wholesale price is inefficient, and builds costs into the system that are paid for by all other consumers.

3. *Do you think any other near-term arrangements or changes to the market design can be explored in this workstream?*

As noted above, demand side participation is significantly diminished by existing barriers in the system, but is available to customers who wish to engage and is continuing to evolve. The AEC encourages the ESB to provide advice to Governments as to how to reduce barriers to participation in a manner that does not fundamentally disadvantage customers who do not wish to participate. This would place a priority on identifying barriers and considering their overall impact on the market and customer outcomes.

This will require a rethink of the historical model where all customers receive 'full' protections, with customers who seek to participate gaining incremental benefits above and beyond this. While some customers may wish to fully participate in the market, many others will not. To this end, the AEC considers consideration needs to be made as to whether or not there are benefits in enabling customers to opt out of minimum standard protections so as to participate more fulsomely in the market.

Similarly, the AEC considers that some steps should be taken to understand the impacts of existing ‘protections’ on other customers. For example, in Victoria, retailers are unable to offer products that are not able to be taken up by solar customers. There are clearly other impacts from price regulation (in particular, enabling solar customers to access default offers intended for customers who are unable to, or do not with to, engage in the market) that should be considered as part of this review.

4. *What measures should be deployed to drive consumer participation and engagement in two-sided market offerings, and what consumer protection frameworks should complement the design?*

Competition should be deployed to drive consumer participation. Where benefits exist to consumers and aggregators to increase participation, the market framework should be flexible enough to enable these providers to offer these services.

The existing retail market framework does not provide for this flexibility.

Customers are precluded from making choices that might benefit them due to concerns that customers who are unable to make such a choice may be disadvantaged. The AEC strongly supports efforts to ensure consumers are able to equitably access the benefits of retail competition, but existing measures such as price regulation, and one-size-fits-all consumer protections dampen price and investment signals, and increase overall prices paid.

In principle, consumer protections frameworks should enable those who wish to engage and actively participate in the demand side to do so and benefit, while those who do not wish to participate should not be unfairly disadvantaged.

As noted above, for customers who wish to take greater control over the management of their energy usage, a question needs to be asked as to how much of the existing consumer protections regime remains necessary. For example, it might be more efficient if customers who wish to engage a trader to aggregate their consumption did not retain access to retail price caps that are balanced to capture the peaks and troughs of a customers demand profile.

Overall, as new services are developed, the consumer protections framework should be malleable enough to ensure customers to obtain the protections they need for that service, but no more. The current framework that places obligations on participants by type, rather than placing obligations on the types of services being delivered, is not appropriate in a two-sided market and imposes additional costs on some participants for limited benefit.

5. *What might principles or assessment criteria contain to help assess whether it is timely and appropriate to progress through to more sophisticated levels of the arrangements?*

The AEC does not consider that an objective of a two-sided market with all load scheduled in a manner similar to generation capacity is the right approach at this time. Of primary importance is for the ESB and other market bodies to identify and seek to resolve actual barriers, be they regulatory or non-regulatory, and develop targeted and proportionate measures to mitigate them.

There are additional matters that should be considered when assessing whether or not steps should be taken to make a market more two-sided. These matters include the potential size of the demand side market, the reasons it does not exist today, and the benefits to consumers if it were implemented. As a matter of principle, markets should not continue to be developed where there is no consumer demand.

MDI - F VALUING DEMAND FLEXIBILITY AND INTEGRATING DER

DER will play an important future role in the potential for lowering both energy and distribution costs and providing economic and environmental benefits that will flow to the end users, the owners of DER and the distribution networks.

The question of how to kickstart DER has led to jurisdictional approaches that have seen the emergence of distributor centric policy making. Whilst there may be certain services where a distributor led technical solution is more cost effective for the overall system, the AEC holds a strong preference towards markets that compensate customers for the services provided.

It is still early days for DER orchestration. The significant upgrades to DER communications and back end systems that will be required to fully integrate DER should be informed by trials and undertaken when the cost benefit case is better understood. Distribution level markets that enable trading between local buyers and sellers is another possibility for the future. Co-optimising DER services across different markets may be the ideal outcome, but this is still a long way off due to the infrastructure requirements and current uptake levels.

For now, the key for DER integration is to access the more readily accessible opportunities such as demand response and network support services, and then let more sophisticated distribution level markets evolve.

Section 9: Paper Questions

1. *(a) Are there any key considerations for the incorporation of DER into the market design that have not been covered here?*
   (b) For DER to participate in markets, it needs to be responsive. How should the Post-2025 project be thinking about enabling responsive DER?

Valuing demand flexibility and efficiently integrating DER is not simply about technical standards, but the need to act now to get the market institution right. The AEC has consistently argued that the regulatory framework governing DER integration must, as its first priority, empower consumers with the choice to utilise and optimise their own DER assets.

Enabling responsive DER means enabling consumers with DER to participate in competitive market services for the provision of the energy system's broader needs. The AEC remains concerned that the rise of distributor centric models that displace the consumer as the centre of DER frameworks are jeopardising the emergence of a competitive market for DER services.

The 2017 KPMG Report on Distribution Market Models[6] ("**KPMG Report**") prepared for the AEC addressed Energy Networks Australia proposals[7] for the network services component of DER ("**the Roadmap**"). Specifically, the proposal to establish a network optimisation market ("**NOM**") to enable distribution network service providers ("**DNSP**") to procure DER for the purposes of Network Support Services ("**NSS**").

As part of their Report, KPMG[8] identified the following three priorities for DER market integration:

1. The ability of DER to be co-optimised across multiple value streams.
2. The ability of customers to capture the full value of their DER services.
3. No conflicts of interest.

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[6] KPMG Report on Distribution Market Models https://www.aemc.gov.au/sites/default/files/content/42e8670a-ae14-4e66-abd9-d1e885a18e98/MarketReview-Submission-SEA0004-KPMGI-170717-%283%29.pdf

[7] Energy Networks Australia and Commonwealth Scientific and Industrial Research Organisation. Electricity Network Transformation Roadmap" Final Report. April 2017

[8] Responses to this section are replicated almost entirely from the KPMG Report.

The AEC believes that these remain the three key priorities for DER market integration.

1. The ability of DER to be co-optimised across multiple value streams

The value of DER is maximised when it can be co-optimised across multiple value streams. The emergence of competitive market platforms will create more opportunities for DER resources to tap into different revenue streams. The ability of DER to be co-optimised across multiple value streams, including DNSP's procurement of NSS, will depend on:

- The DNSP providing clarity to the DER owner as to when and how often the NSS service is likely to be required, and the value of that service, so that the DER resource can be efficiently utilised at other times.
- The terms and conditions under the DNSP's procurement of the DER resource for network support services, including the penalty rates for non-compliance as a result of penalties incurred by the DNSP (for example, under the Service Target Performance Incentive Scheme ("**STPIS**")).
- How the DNSP translates its obligations to maintain a reliable, safe and secure network in access and connection arrangements for DER; and,
- Whether the NOM would allow the concurrent operation of competitive platforms and how it is proposed that these interrelate and allow the efficient resolution of co-optimisation issues.

The role and behaviour of DNSPs towards DER can potentially create a barrier limiting the ability to "stack" the incremental values a DER may provide to the wholesale market, distribution networks, retailers, and customers. This is because a DNSP will approach its interactions with DER on these four issues from their own perspective and obligations. Therefore, there is a significant risk of misalignment between the interests of networks and boarder market efficiency with respect to the use and procurement of DER. This misalignment is exemplified in the discussion on standards versus markets later in this series of questions.

2. The ability of customers to capture the full value of their DER services

The capacity for DNSPs to procure DER directly from customers is likely to impede the development of competitive DER markets and limit the ability of DER to capture the full value of its services. This is due to:

- The potential for a DNSP to under-pay the DER owner the associated network value or extract it at no cost. This reflects the DNSP being the single buyer of NSS and is complemented by the cost minimisation incentives under the economic regulatory framework. The current lack of transparency on the potential network value from DER adds to this risk.
- The potential that a DNSP will place restrictive control terms on DER which prevent it from accessing other sources of revenue. While this is driven by the reliability arrangements governing DNSPs (and AEMO), it is also influenced by both the DNSP's and AEMO's risk approach and preferences. There is a risk of inefficient outcomes if such control terms do not maximise market efficiency from DER while achieving the required level of reliability. As the DNSP may not be exposed to the wider market benefits from DER, it may place a greater onus on reliability rather than flexibility.

The optimisation of DER value is a complex question. We believe that the procurement of DER services directly from customers by DNSPs will not result in the optimisation challenge being solved effectively as this places the onus to solve co-optimisation directly onto the customer, who is unlikely to have the ability to resolve it alone.

These also represent compelling arguments to move away from a network centric model that allows the DNSP a direct investment role in DER. A DNSP may choose to continue to develop its own products and services to offer to customers, such as the existing load control products. This could create a barrier to other competitive products if the DNSP is inclined to look more favourably on the products it has developed, and less favourably on products developed within the competitive market, such as those developed by retailers or other third parties.

Furthermore, the DNSP will always have a greater understanding of what its own products can offer and the associated risks and will be able to design those products to match its own preferences. There may also be an incentive associated with the ability to include such assets in their regulatory asset base ("**RAB**"). How DNSP's approach the risk of non-delivery of a contracted DER service will determine the conditions placed on the DER service and its ability to access additional revenue streams. Based on current incentives, the DNSP are likely to either pass all the risk on to the customer or seek to resolve the risk through having automatic control over the DER asset (which in turn requires an investment by the DNSP in the control technology).

We contend that alternative approaches where customers participate through an intermediary/aggregator will allow delivery, co-optimisation and performance risks to be managed between the network business and the aggregator, rather than falling to the customer. Such alternatives are likely to result in a better allocation of risks and the promotion of the development of competitive DER services as they allow the use of DER to be adaptive to the market circumstances that are occurring.

3. No conflicts of interest

Potential conflicts of interest arise for the DNSP, especially if the distribution system operation role remains integrated within the distribution network service provider. A DNSP's financial interest in DER services do not necessarily depend on whether the DNSP owns the DER asset (either directly or indirectly through related parties). A financial interest could still exist through:

- The procurement of services from DER owners by the DNSP, depending on the design of those contracts and how the associated costs are treated under the economic regulatory framework.
- DNSP investment in a market platform (such as the digital NOM) to purchase DER for the network support services.

We are not arguing that DNSPs should not have access to the network support benefits that DER services can offer. In fact, it is essential that they do so in order to achieve a lowest cost system for the benefit of customers. But they should be required to procure them from the competitive market. Robust competition for the provision of this type of services will in turn allow the network to deliver its direct control services at the most efficient cost. It will also allow for co-optimisation of network support services and customer value, given that customer DER cannot necessarily provide both simultaneously.

Enabling responsive DER means the ESB need to act now to get the market institutions right. A market framework with the consumer at the centre of a competitive market of DER services represents the best frame of reference for the ESB in its considerations of the DER MDI.

2. *(a) In the next phase of the project the ESB proposes to focus on development of a detailed DER market integration proposal. What are the most important priorities for DER market integration?*

Australian Standards

Should Australian Standards (or other regulation) be used to compel DER owners to provide services for network owners at the expense of the DER owner? The draft inverter standard AS4777.2 with ride through capability makes this point when considered against the ESB commissioned report from the University of New South Wales. This report found rooftop PV makes only a small contribution to already high voltage levels, and that DER would appear not to be the root cause of the problem.

Whilst customer owned DER can be used to help fix that problem, our view is that that fix should be a function of a market for DER services and not a condition of connection.

We acknowledge that there are limits to property rights, and we accept the obvious primacy of safety, but the current propensity for Australian Standards and DNSP connection agreements to be used to transfer value is of concern. Whilst standards and regulations provide a level of certainty and checkability that is attractive, we contend that they will tend to preclude both innovation and trading over the longer term, where innovation and trading might have provided a similar result at lower cost.

Stranded investment in the Distribution System/Market Operator

At a granular level, an issue is the ability for DERs to access markets. Currently the only way for virtual power plants ("**VPPs**") to trade FCAS is via AEMO's VPP Demonstration Program, which includes program-specific metering requirements and technical settings to make it feasible for DERs/batteries to participate. This program is limited in duration and participating DERs will be unable to trade FCAS after its conclusion unless these requirements and settings are carried over into the ongoing markets. Carrying over these requirements and settings would give DER investors confidence that they can access this market and provide benefits to customers that reflect this revenue opportunity.

At a macro level, investment in the Distribution System/Market Operator ("**DSO/DMO**") for a mass market of DER for network optimisation is also contingent upon solving this root problem. As a corollary, distribution network optimisation, such that there is currently a market, exists in the form of the Regulatory investment test for distribution ("**RIT-D**"). And as an effective competitive alternative to distribution businesses' capital expenditure plans, the RIT-D is not delivering. The AER's 2018 review of the RIT-D Guidelines demonstrated this; the AER identified only one successful non-network project from 10 competitive assessments and 16 RIT-D reviews since the RIT-D's introduction in 2013.[9] It would therefore appear risky in our view for any entity to devote to facilitating heavy investment in DER participation in any commercial trading facility connecting the DER to a buyer (a DMO) if, taken as given the performance of the RIT-D, distribution networks will bypass any market via the use of connection agreements or direct control. This risk of bypass needs to be addressed in any proposed market framework.

Customer pricing

Electricity consumers have historically had limited desire to respond to cost reflective prices and this has now been institutionalised by the Victorian Default Offer and Default Market Offer. This limited customer desire for cost reflective pricing is also apparent in the generally available market offers of largely flat and price guaranteed tariffs by retailers. These offers accommodate the desire for price certainty amongst consumers; often overriding network tariffs that attempt to sharpen the signal in the process.

Therefore enabling price response for DER requires tackling two difficult problems:

1. To allow networks to charge for costs incurred in supporting the export of electricity by DER participants. This would include the explicit removal of Rule 6.1.4 from the NER.
2. This charge should be locational to reflect the fact that the cost imposed by export will vary from place to place.

There has been a considerable consumer representative shift in thinking as to how to address the costs to consumers created by DER exports. As a result, there are now three rule change proposals

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[9] The regulatory investment test for distribution (RIT-D) rule change proposal, Australian Energy Council, https://www.aemc.gov.au/sites/default/files/2020-08/ERC0314%20Rule%20change%20request%20pending.pdf

with regard to the pricing of export services under consideration by the AEMC. This AEMC consultation will address 1 and 2 above, and we urge the ESB not to run a parallel process in this regard.

A national approach

The post 2025 project should however concern itself with a decision around standards versus price signals (market-based outcomes) as one of the foundation steps to enabling responsive DER. This decision will always be a trade-off between administrative costs, efficiency benefits and consumer comprehension, along with overarching non-negotiable issues such as safety.

Unfortunately, today in the absence of consistent national policy this unresolved dichotomy is creating havoc; contemporary examples being the South Australian Government mandate for unique meter standard requirements and the Australian Standards mandate for unique inverter obligations. Feasible alternatives exist to managing these issues and reduce costs, and in the longer term relying on a market to deliver outcomes makes more sense than relying upon standards. Much of the DER is manufactured overseas, and unique local standards will simply diminish the technology pool from which small consumers may purchase, limiting both choice and price competition.

2. *(b) The ESB is considering combining the DER integration and two-sided markets workstreams, or elements thereof, do stakeholders have suggestions on how this should be done?*

The AEC has no objections to integrating the two streams.

3. *(a) How can we ensure that owners of DER can optimise the benefits of their DER assets over time as technology and markets evolve?*

Aside from the risk that networks preference their own investments over more efficient solutions, networks have made some effort in exploring different approaches to making the market benefits of their DER investments available to others.

The approach used in United Energy’s Bayside Battery Project, for example, where market participants had the opportunity to bid for the wholesale market and FCAS benefits of the DER, enables more of the value of the DER to be monetised than the Ausgrid approach, which offers DER as network services that may or may not be taken up by customers on an individual NMI basis. In this latter case it is difficult to see how FCAS, for example, can be aggregated and provided to the market. We do not directly support either approach, but these network projects do show that there are opportunities for networks and other market participants to work together to maximise the value of investments in DER by providing the widest range of services they are technically capable of. What is required is regulation to align the behaviour of network businesses to the wider market efficiency.

3. *(b) How do we time reforms to manage the costs and benefits for DER owners?*

Regardless of the timing of reform, any network impacts are unlikely to be uniform - both in time and magnitude - across all distribution networks. This uncertainty is likely to be exacerbated as differing technologies come to market, with varying operating profiles. Given the risks and costs of regulation, we believe that there is a need to consider how best to promote the development of competitive providers of DER services and commercial platforms and let the market evolve.

MDI – G TRANSMISSION ACCESS AND THE COORDINATION OF GENERATION AND TRANSMISSION

The development of transmission, its co-ordination with generation siting, and the efficient dispatch of generation across it, are clearly major challenges for the NEM and have no easy answers.

The AEC notes many commentators, governments and developers keen to see very large investments made in the NEM's transmission grid, funded by customers and/or taxpayers. This is often presented as an essential part of transition: where it is suggested that security, reliability and carbon abatement are entirely dependent on such a scale of investment.

The AEC rejects such an unnuanced narrative. These three objectives can equally be delivered through local options, such as peaking generation, storage, demand-side response and DER. Indeed, the Western Australian Whole of System Plan[10] proposes a future that successfully achieves all three with effectively no new transmission.

Ultimately the industry definitely has a choice at or anywhere between these two extremes. The choice should be purely derived from good economics such as that enshrined in the Regulatory Investment Test for Transmission ("**RIT-T**"). Nor does it need to be a conscious choice made by the ESB or government long ahead of time. Instead, each possible transmission project should be assessed individually on its merits: whether it provides individual benefits that exceed its cost. Over time, this process will organically either deliver the three objectives through a deep national grid, or through disaggregated supply. Or, more likely, somewhere in between.

Whilst it may be discomforting to not have up front certainty about exactly how the grid will evolve, this should be accepted and embraced. It is why markets are repeatedly proven as the best way to deliver services: they maximise opportunity for innovative solutions and the evolution of technological change.

With respect to introducing a more granular pricing structure than the existing regional structure, the AEC acknowledges a range of views on the materiality of this matter. It is however uncontested that there exists significant issues in the co-ordination of the physical construction of the grid and generator connections. Indeed many new generators are facing unexpected delays and output limitations to due to local technical issues that cannot be represented in a congestion signal. These local connection issues are potentially more pressing than a lack of granular pricing.

Section 10: Paper Questions

1. *The Integrated System Plan is now in its second year. Do you have any comments on how its implementation can be made more efficient and timely?*

The biennial ISP provides an expectation for transmission development over the coming 20 years, based on assumptions and scenarios AEMO has developed in consultation with stakeholders. This plan is neither static nor definitive, therefore when Transmission Network Service Providers ("**TNSPs**") seek to undertake projects suggested in the ISP, they must perform their own due diligence in relation to each project's viability according to the requirements of the Regulatory Investment Test for Transmission.[11] There is no doubt that the ISP, with its detailed scenario development, is a good starting point for TNSPs, but it provides a limited set of possible futures which are subject to inaccuracies and unpredicted outcomes, and the best project for a TNSP at a given point in time must be assessed by the TNSP's own enquiries.

[10] https://www.wa.gov.au/organisation/energy-policy-wa/whole-of-system-planning
[11] National Electricity Rule 5.16

In the AEC's view, while there is a role for a centralised entity to collate information and inform participants, it is beyond the capabilities of a central planner to anticipate and respond nimbly to market changes. Accordingly it is appropriate for market design to be such that it provides a framework within which participants can operate, but not be so restrictive as to curtail innovation and limit market efficiencies.

The AEC considers that ultimately the ISP provides a useful guide to the TNSPs to assist the development of a cohesive national grid, but, having published it, it should then become fully the responsibility of TNSPs and AER to develop and justify the projects in detail subject to individual assessment under the cost-benefit framework of the RIT-T. If, during this more detailed phase, an ISP recommended project is substantially altered or rejected, then that result should be welcomed and is in no way symptomatic of any planning failure.

2. *The cost of major transmission investment projects is of concern. Do you have any suggestions on how these projects can be built for less than currently expected? Why have costs increased so markedly? Given the rising costs, are there alternative approaches to transmission project development, design and implementation which could lower the cost?*

With $23bn being proposed for expenditure over the next 20 years in the ISP, transmission can no longer be considered as a relatively small component in the cost stack for electricity consumption. The apparent inflation of the costs of new transmission infrastructure is of course a concern to the AEC, however the AEC is not qualified to comment on the reasonableness of this trend beyond noting the key importance of the role of the regulator in ensuring efficient expenditure.

A clearer concern to the AEC is observed increases in cost estimates of projects from those forecast in the ISP and in RIT-Ts and those that emerge later during revenue applications. Poor estimates at the justification stage seriously undermine good decision making in the planning of the NEM.

The AEC recognises that early planning estimates will incorporate a degree of error, however recent examples of dramatic and sudden cost increases raise serious concern that insufficient attention is being applied to the initial estimates. Even more concerning is anecdotal evidence of a bias toward under-quoting, and the AEC recommends the AER undertake historical analysis into the extent of this.

Greater confidence in the estimation process could be achieved if these had direct impact on the recoverable expenditure. Thought should be applied to whether this allowable revenue can be capped at the levels estimated at the RIT-T stage. The AEC accepts this is not straightforward, but if possible there are clear incentive attractions in doing so. It would create both a natural incentive to avoid under-quoting which would restrict allowable revenue, balanced by a natural incentive to avoid over-quoting which lessens the chance of a project passing the RIT-T. The ultimate result likely being a much more thorough and confident early costing, which is not unreasonable given the magnitude of the projects being charged to customers.

3. *The development of Renewable Energy Zones is important for the transition underway in the NEM. Do you have any suggestions on how large-scale priority REZs can be more efficiently developed and connect into the network?*

While the concept of REZs is helpful in considering the issues facing new variable renewable energy generation development, in practice there are difficulties in accommodating them within the increasingly meshed transmission network.

The AEC believes that codifying the REZ concept may risk existing functioning activities, as this may:

- add administrative burden to processes;
- slow the process of evolution and innovation in the REZ concept; and,

- create boundary issues and disputes between superficial classifications.

The AEC's submission to the REZ Planning Consultation Paper and Draft Rules is pertinent to this question,[12] and confirms the AEC's belief that generators should connect, and transmission should develop, subject to economically efficient commercial drivers, rather than as a result of external intervention.

4. *NERA Economic Consulting's modelling of the benefits of introducing transmission access reform in the NEM has been published. What do you think about the modelling and assumptions used? What does this suggest about how fit for purpose the current access regime is? If you are unsure of the merits of locational marginal pricing and FTRs what other suggestions would you make about how risks of congestion might be managed by generators?*

The AEC has provided more detailed comments into the AEMC's consultation process.

The AEC has concerns about the cost-benefit information provided with the COGATI process:

- The benefits of avoiding 20GW of wasteful investment that might otherwise occur in the regional design seem quite hypothetical and difficult to reconcile with historical investment practice.
- When considering the NEO, only net market benefits should be contemplated and wealth transfers excluded.
- The costing side seems unrealistically low with respect to a major IT redesign project in the NEM. The participant costs have been estimated at about one-sixth of those costs that an AEC survey has revealed were borne in market participants for the 5 minute/global settlement changes.
- The contracts cost impact seems to be purely administrative/legal costs. A major change in market basis must introduce a period of uncertainty which should reveal itself as a period of increased cost of funds to the industry until the new arrangements are understood.

The AEC is concerned regarding the proposed timing of the reform in 2025 coinciding with other major changes and prefers some years' clearance beyond any changes out of RAMs or major ESS design implementation.

It is also noted that despite the reform being assessed as being implemented in 2025, the benefits largely accrue post 2030. This provides the option to defer implementation beyond 2025, or, to retain the 4-year notice period but to defer and revisit the issue toward the middle of the decade.

5. *The AEMC has released an updated technical specification paper on the transmission access reform model, alongside this report. The updated proposal provides additional information on the options regarding the design of the instruments, pricing, and trading. How well do you think the proposal would address the identified challenges?*

The AEC is engaging in detail with the proposed design of the access reform model in its submission to that paper and will not repeat most of that here.

The AEC considers transitional arrangements are an essential part of making any design practically implementable. The AEC recognises efforts to develop a fair mechanism to allocate initial quantities, although is hoping to see example calculations. The AEC agrees with progressively declining the quantities but considers, in recognition of the typical investment cycles of the industry, that it should occur over at least ten years and be fully tradeable.

[12] Available at https://www.energycouncil.com.au/media/19088/20200908-aec-rez-planning.pdf

APPENDIX

CREATIVE ENERGY CONSULTING REPORT ("CEC2")

Scheduling and Ahead Markets

Submission to the ESB Consultation Paper

Creative Energy Consulting Pty Ltd

October 2020

EXECUTIVE SUMMARY

OVERVIEW

The Australian Energy Council has engaged Creative Energy Consulting to prepare a submission, on the area of scheduling and ahead markets, to the ESB's recent post-2025 NEM design consultation paper. This follows on from an earlier engagement in this area, which culminated in a paper that was submitted to the ESB in June. This submission draws on that June paper's framing and analysis of the issues, applying that thematic structure to the ESB's latest proposals.

There are some welcome developments in the latest ESB papers. In particular, design options involving mandatory ahead market participation have been ruled out, and some more detail around the ahead market design has been developed and presented. However, the papers have still not satisfactorily answered the basic questions posed in our June paper: what specific problems are seen to be emerging with the current scheduling process; how an ahead market would address these; and why other potential options are not being explored.

Building on these generic questions, five specific areas of concern arising in the new ESB papers are identified and discussed in this submission:

1. Possible reforms to pre-dispatch have not been discussed
2. A voluntary, "net" ahead market cannot perform a scheduling role
3. The UCS scheduling principles remain unclear;
4. The ahead market should not schedule non-market ancillary services
5. The value of ahead hedging is low.

These are explained further below and discussed in detail in the main body of this paper.

PRE-DISPATCH REFORM NOT DISCUSSED

Our June paper described in detail the existing design of the pre-dispatch process and its role in the scheduling and commitment of generation over the "ahead" timescale. It also presented some ideas for reforms to this process that might be considered. The consultation paper acknowledges the former but has ignored the latter. The entire focus of the paper continues to be to create an entirely new process – the ahead market – whilst implicitly assuming that the existing process continues to operate, unchanged, in parallel.

Such blinkered analysis jeopardizes the success of the post-2025 design review and so the future effectiveness of the NEM. Because if, as seems probable for reasons discussed below, the revised design fails in its efforts to address its scheduling concerns by implementing a new ahead market, there is no "Plan B" of alternative design options and the market design must rely on the continuation of the status quo. This is not to say that the current pre-dispatch design will necessarily fail to perform effectively under a future, transformed energy mix. Indeed, as our June paper argues, the decentralized architecture of pre-dispatch makes it well-suited to adapting to such change. But the purpose of the post-2025 review is to carefully examine these future challenges and present a range of options to address them. The papers' analyses continue to fall short of this objective.

A NET AHEAD MARKET CANNOT PERFORM A SCHEDULING ROLE

The current pre-dispatch process is "gross" in that it incorporates and encompasses all dispatchable generation, load and transmission resources in the NEM. That is achieved by making participation in the process mandatory; any resource participating in the real-time market must also participate in pre-dispatch. This gross participation allows AEMO to verify and ensure that the pre-dispatch schedule is reliable, secure and economic; the critical goals of any scheduling process.

The ESB has (rightly) decided to make participation in its proposed ahead market voluntary. So operators of resources will participate only if it is commercially advantageous to do so. But this would be the case only if the existing market channels – the real-time market and the forward markets – were disrupted or undermined. And that, of course, is something to be avoided rather than sought.

It is likely, then, that ahead market participation will instead be "net", with only a minority of resources participating. This means that it cannot perform the scheduling role that the papers suggest.

The UCS should follow existing scheduling principles

Our June paper offered support for ESB's proposal that AEMO develop a new scheduling algorithm – referred to as unit commitment for security (UCS) – that would help inform "intervention" decisions around scheduling of directions and non-market ancillary services. However, from a market design perspective, the key concern is not the scheduler itself but the scheduling principles that inform its functionality and operation.

Existing principles are set out in Rules and procedures. Incorporating these same principles into the UCS would be natural and uncontentious. Indeed, that would seem to be an operational matter for AEMO to consider and advance, requiring neither Rule changes nor the oversight or involvement of the ESB or any other market body.

Conversely, the ESB's active interest in the UCS suggests that changes to the scheduling principles are being considered, but exactly what these might be remains unclear. It would be helpful for the ESB to clarify its intentions and expectations in this area.

The Ahead Market should not schedule Non-market Ancillary Services

Ancillary services are non-energy services that are procured by AEMO to ensure system security. They are categorized as market or non-market, depending on whether they are procured in the spot market or through term contracts, respectively.

AEMO currently schedules deployment of non-market ancillary services in accordance with contractual terms: eg these might require a notice period for plant to start up. One key role of the proposed UCS is to improve this scheduling process.

In the papers, the ESB envisages that the ahead market could also play a role in the procurement and/or scheduling of these non-market ancillary services, similar to how this would apply to energy and to *market* ancillary services. However, this approach appears both inappropriate and impractical. Inappropriate, because the concept of a financial and voluntary ahead market requires that there is also a physical, mandatory, real-time market; which, by definition, does not exist for non-market ancillary services. Impractical, because scheduling of these services is extremely complex (think of system strength as a potential example of such a future service) and it is implausible that such complexity could be incorporated into an ahead market.

In any case, the proposed UCS should provide an effective, customised mechanism for scheduling of non-market ancillary services. The involvement of the ahead market is an unnecessary complication.

The Value of Ahead Hedging is Low

It is accepted that there is potential value in an ahead trading platform that allows generators and retailers to adjust their forward positions in the light of the latest available weather and demand information. This idea has been explored regularly, most recently in the AEMC's assessment of AEMO's "short-term forward market" rule change proposal. Generally it has been concluded, as our June paper did, that:

- the value of such hedging is likely to be low and outweighed by the associated transaction costs; and
- if market participants saw value in it, they (or independent service providers) could set up the platform themselves, as has happened with forward market trading platforms generally.

The papers illustrate the potential value of ahead hedging using the example of day-ahead demand response, which might be encouraged if its uncertain value to the consumer could be hedged. But demand response already occurs in the market, with these risks typically borne by the retailer rather than the end-user. For a retailer, the risks are modest and are anyway more easily managed within its retail portfolio.

Despite its inherent inability to operate as a scheduler (for the reasons discussed above), an ahead market could still have merit if able to provide substantial hedging value. But the papers have been unable to demonstrate this and it remains implausible.

CONCLUSIONS

In its latest papers, the ESB is no closer to answering the three basic questions that are fundamental to any market design reform. It has still failed to explain, except in the most general terms, what its concerns with the pre-dispatch-based scheduling process are. It has not articulated how an ahead market can help. And it still ignores alternative design options based around changes to the pre-dispatch process.

Ahead markets are tired and anachronistic, with no relevance to the NEM, and it is recommended that the quest to design and implement them should be abandoned. Instead efforts should be focused on identifying reforms that build on the strengths of the NEM's existing scheduling processes.

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1 INTRODUCTION

1.1 BACKGROUND AND SCOPE

Creative Energy Consulting (CE) has been engaged by the Australian Energy Council (AEC) to review the Energy Security Board's (ESB's) latest proposals for possible changes to the NEM design, relating to scheduling and ahead markets. This paper contains CE's analysis and conclusions.

The ESB's proposals in this area are largely contained in two papers:

- The "Consultation Paper"[13]
- The "Market Reform paper"[14]

CE has also reviewed other new material from the ESB covering related market design initiatives (MDIs): the Essential System Services (ESS), Two-sided Markets, and Coordination of Generation and Transmission Investment (COGATI) MDIs.

Finally, CE has undertaken a high-level review of reports emanating from two recent Australian Energy Market Operator (AEMO) consultations:

- Network Support and Control Ancillary Services Descriptions and Quantity Procedure Amendments[15]
- Reliability Standard Implementation Guidelines, Medium Term Projected Assessment of System Adequacy (MTPASA) Process Description[16]

CE was previously engaged by the AEC earlier this year to undertake a more general analysis of scheduling and ahead markets issues and options. That engagement culminated in a written report[17] ("our June paper") that the AEC subsequently published and also submitted to the ESB. Because the analysis in that paper was largely generic[18], it remains relevant and pertinent despite the new analysis and proposals that the ESB has since released. Therefore, it is extensively referred to in this paper and sets an important context and foundation for this paper. Unlike that paper, this paper confines itself to the specifics of the ESB's latest material.

1.2 APPROACH AND STRUCTURE

The approach that has been taken is to review the likely efficacy, appropriateness and completeness of the ESB's proposals in the context of the generic frameworks and analysis developed in the earlier engagement and presented in our June paper. Some five main areas of concern have been identified:

1. Possible reforms to pre-dispatch have *not* been considered;
2. A net ahead market cannot perform a scheduling role;
3. The scheduling principles for the Unit Commitment for Security (UCS) algorithm remain unclear;
4. The ahead market should *not* schedule non-market ancillary services; and
5. The value of ahead hedging is low

A section is devoted to each of these issues. Each section is structured as follows:

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[13] *Chapter 7*, *Post-2025 Market Design Consultation Paper*, Energy Security Board, September 2020
[14] *Scheduling and Ahead Markets*, Market Reform, undated
[15] *NSCAS Description and Quantity Procedure Review Final Report and Determination*, AEMO, September 2020
[16] *ST PASA Replacement, Functional Requirements*, IES and SW Advisory, 20 May 2020
[17] *Scheduling and Ahead Markets: Design Options for post-2025 NEM*, Creative Energy Consulting, June 2020
[18] although one section was devoted to assessment of the ESB's proposals as they stood at the time

- The issue is summarized.
- Relevant extracts from our June paper are presented.
- Relevant extracts from the ESB's new material are also presented.
- Differences between the ESB's approach and the preferred approaches set out in our June paper are identified and analysed, with the implications drawn out.
- Conclusions are briefly set out.

Finally, the specific questions posed by the ESB in the consultation paper are answered in an appendix.

2 Possible Reforms to Pre-dispatch Have Not Been Considered

2.1 Summary

Pre-dispatch (PD) is the scheduling platform in the current NEM design. If there are concerns that PD might not be effective in dealing with emerging scheduling challenges in the energy transition, then potential enhancements to the PD process should be explored. An ahead market will face the same scheduling challenges and does not, in itself, present a solution to these.

2.2 What Our June Paper Says

An issue raised by the ESB is that, in the future, the PD process may not be effective for scheduling and coordination. Whilst it is not clear that this is an issue in the NEM currently, past and current fitness does not *necessarily* imply future fitness, given the substantial changes expected in the generation mix and in demand behaviour over the time period being covered by the ESB review. Indeed, if dispatch problems are addressed – by introducing new AS spot markets and contract markets and by increasing the complexity and sophistication of the NEM dispatch engine (NEMDE) – this might fundamentally change the nature of the scheduling problem: for example by placing greater reliance and dependence on commitment of synchronous generation to provide the new Ancillary Services (AS).

Considered in its entirety, the PD process is a sophisticated, organic scheduling process which is likely to be superior in its performance, robustness, transparency and adaptiveness to any "black box" centralized scheduling algorithm that a system operator could come up with. It is, perhaps, not always recognized as such because of the simplicity of the PD engine that lies at its heart. But the PD engine design is in fact powerful in that it mimics the dispatch algorithm and so largely eliminates the seams between PD and dispatch that would be inevitable if a more complex and sophisticated PD engine design were used. Complexity, instead, lies hidden in the trading systems of market participants, who are directly motivated to develop and fund the sophisticated processes needed to achieve their scheduling objectives.

The current PD engine is set up to mimic NEMDE. However, this is not inevitable. Indeed, since PD operates ahead of real time and over an extended study period, many different scheduling engines are possible. A different PD engine might potentially address…issues around convergence or effectiveness of the PD process.

[Alternatively] simpler reforms might achieve this goal: [such as] more frequent PD runs; fewer restrictions on bids and rebids; or multiple PD scenarios.

Identifying any changes to the PD process, that could improve its effectiveness and robustness, should have been the starting point for the ESB's design investigations. New ahead markets can, at best, complement the PD process and may, instead, compromise or undermine it.

2.3 What the Recent ESB Papers Say

"Pre-dispatch plays an important role in providing an indication of expected dispatch and pricing. The information provided here … is used by market participants to co-ordinate their resources and self-commit to the market" (P76)

"…over recent years, there has been increasing uncertainty in both supply and demand translating to an increased uncertainty in pre-dispatch system conditions, from:

- More VRE with inherent weather-dependent variability and forecast uncertainty.
- More DER that is not visible to the operator and cannot be controlled by the security constrained economic dispatch process.
- Application of algorithmic and high-volume bidding.

- Dynamic response from participants to changing conditions in the pre-dispatch period up to dispatch." (P76)

"Participants rely on the signals given through pre-dispatch to make these decisions, and advise their self-commitment decisions to the market via the bids they provide. Bids provided to pre-dispatch must be given in "good faith" and can only be changed in the lead up to dispatch where conditions have changed.

However, with pre-dispatch becoming more uncertain, there are inherently more changes in the pre-dispatch timeframe, leading to changing bids. This in turn leads to a change to the pre-dispatch, creating a circular trend, eventually converging in time towards dispatch." (P78)

2.4 Discussion

The consultation paper acknowledges the central role that PD plays of scheduling and coordination in the NEM. It also expresses concerns around whether the current PD design will remain effective in the future; and even presents some historical analysis suggesting that its performance has deteriorated in recent years[19]. Despite this (and despite the salient fact that this MDI is entitled "*scheduling* and ahead markets"), there is no suggestion from the paper that the ESB has investigated – or even *contemplated* investigating – possible changes and reforms to the PD process. Nor is there any suggestion that it plans to do this in the remainder of the post-2025 review. Our June paper made some suggestions for reform elements and areas, but the consultation paper does not consider or even acknowledge these ideas.

This strategic blindspot is surprising and remarkable. Whilst the ESB might be of the view that the introduction of ahead markets will address or mitigate any PD failings, it cannot test this view unless it analyses PD and investigates PD reform options. Indeed, since the solutions proposed in the consultation paper (particularly UCS), rely on PD outcomes[20], then an unreliable PD means that it is building on suspect (in the ESB's view) foundations. Furthermore, the NEO requires that the *best* reform option must be implemented. The ESB cannot know that an ahead market design clears this hurdle unless it investigates all plausible alternatives: of which a reformed PD process is clearly one.

The paper's ahead market options rely on sophisticated new scheduling algorithms to clear the market: ie to determine cleared quantities and prices that match supply and demand, whilst complying with technical and commercial constraints. So the ESB *does* seem to be investigating new, enhanced scheduling processes as part of this design process. But what it is apparently *not* doing is considering whether these new algorithms could be more effectively incorporated into the existing PD process (by replacing the existing PD engine[21]) rather than forming a part of an entirely new platform.

In short, the ESB should be considering *both* dimensions of the scheduling problem:

- the appropriate technical design of the scheduling algorithm; and
- the framing of this algorithm within the NEM design: ie as an ahead market or as a forecasting and coordination process (such as PD).

In parallel with the post-2025 review, AEMO has recently been undertaking its own investigations into new scheduling algorithms, but in the context of MTPASA[22] rather than PD or ahead markets. AEMO's consultants[23] have recommended, in their final report to AEMO, that MTPASA should employ a sophisticated scheduling engine[24]. Although the focus is on the MTPASA window, it is possible that this initiative could also help to address concerns around scheduling efficacy in the ahead window. For

[19] figures 25 and 26, consultation paper
[20] the ESB's "USB only" Option 1 relies *entirely* on PD for market scheduling
[21] note that the PD engine itself is based on the dispatch engine, which is also a market clearing algorithm
[22] as part of its review of the MTPASA process description. MTPASA operates in the 7-day window ahead of PD
[23] IES and SW consulting
[24] a security-constrained economic dispatch algorithm, with inter-temporal optimization. It is unclear whether this would include central commitment of slow-start plant, but it *would* schedule cycling of storage

example, storage operators might use the MTPASA results to inform the storage cycles that they bid into PD[25].

It may be helpful to discuss these issues with AEMO and its consultants – if this is not happening already – and analyse how this MTPASA change might impact on concerns, and proposed solutions, around ahead scheduling.

[25] As discussed in our June paper, using a complex scheduling algorithm in PD would introduce a *seam* between PD and dispatch, in the sense that they would be using different scheduling engines and bid structures. An alternative approach, implied by the MTPASA recommendations, is to use common scheduling algorithms across PD and dispatch, as now, whilst introducing a new complex scheduler in MTPASA. So, the seam would be between MTPASA and PD. Which is not really an issue, *prima facie*, since such a seam has always existed in the current NEM design

2.5 CONCLUSIONS

In the metaphor of the old desert-island joke[26], the ESB appears to have "assumed a can opener". Its solution to the scheduling problem is not to implement an ahead market, *per se* (this is, in a sense, incidental), but rather to assume that it can develop an all-singing-all-dancing scheduling algorithm to form the core of this new market. This magical new algorithm will solve all of the difficulties that PD currently faces: uncertainty; integer decision making; co-optimisation of energy with new, exotic system services; incorporation of the demand side; and so on. Which begs the questions: if you can develop such a scheduler, why not use it in PD[27]? And if you *can't* develop one, why won't the ahead market endure the same difficulties and shortcomings as PD?

There is no time left in this project for further magical thinking. The ESB should adopt a pragmatic and systematic approach to the scheduling problem: identify when and where PD's putative failings might arise; consider what changes are needed to the PD engine, and the PD process generally, to address these; and, only then, to consider whether scheduling can be further improved by using newly-identified scheduling algorithms to form the core of a new ahead market.

[26] in which an economist is washed up on a desert island, along with other individuals from more practical professions. Each in turn suggests how they might open the cans of food that have washed up with them. The economist's solution is straightforward: "first, assume a can opener…". As an economist myself, I find this an unfair characterization of our dismal profession. But, of course, we must always be careful not to assume the solution.

[27] this is not to say that PD *should* incorporate a more sophisticated scheduling engine, even if that were feasible. As our June paper discusses, there are substantial advantages in having a decentralized architecture in the PD scheduling "mega-algorithm" and also in having the PD engine use the same functionality as the dispatch engine

3 A NET AHEAD MARKET CANNOT PERFORM A SCHEDULING ROLE

3.1 SUMMARY

The scheduling problem is a physical one and must encompass the entire physical market. The PD process is able to schedule because PD participation is both physical and mandatory[28]. The ESB now proposes that the ahead market is financial and optional, and so participation in it is likely to be limited. It will therefore *not* be able to perform a scheduling role.

In developing its ahead market concepts, the ESB appears to persistently assume full participation. Something has to give. If the ahead market is going to be a scheduler, participation would have to be effectively mandatory: whether *de jure* or *de facto*. But that would entail a major disruption to the market that would be costly and disproportionate to the scheduling issues the NEM faces.

3.2 WHAT OUR JUNE PAPER SAYS

The possible role of an ahead market in scheduling and coordination depends on whether it is physical or financial. A financial ahead market is going to be voluntary and net, so if there is any scheduling and coordination happening, it only relates to a part of the market. Furthermore, because there are no security constraints included in the clearing process, it cannot represent or reflect the complexities of dispatch in the way that PD does.

On the other hand, a physical ahead market might be gross and could incorporate security constraints, depending upon the design details. So, potentially, the ahead market outcomes could be reasonably reflective of dispatch conditions and constraints.

3.3 WHAT THE RECENT ESB PAPERS SAY

"Option 4 …requires all resources to participate in the ahead market and the ahead schedule can be physically binding even for services that have real-time spot prices."

"The ESB does not wish to proceed with [option 4] at this stage. The ESB considers that the voluntary ahead market options described above are likely to be broad enough in scope to meet the desired objectives while allowing the market to adjust to real-time conditions. "

[28] for all scheduled and semi-scheduled participants

3.4 Discussion

The fact that the ESB has now ruled out ahead market design options which involve mandatory participation is welcomed. As discussed in our June paper, it is difficult to see how such designs could be made to work without fundamentally undermining the real-time market.

However, this introduces another problem, that was also discussed in our June paper: that a voluntary, or "net", ahead market will not be able to perform a scheduling role, given that this market sees only a small part of the overall picture.

The ESB appears not to recognize this difficulty. Indeed, it is notable that the examples it uses to illustrate how the market might operate[29] implicitly assume "gross" and physical participation. It also refers at several points to generators bidding their "ahead market schedule"[30] into PD. Since the ahead market is financial – so it doesn't refer to physical plant – this would not be true even of a gross ahead market[31]. But it is far less true of a net ahead market, where the "ahead market schedule" may represent only a small part of the physical position. This is another critical blindspot in the ESB's analysis.

Some markets do use ahead clearing as part of the scheduling process: in particular, US electricity markets and the Victorian gas market. Critically, these markets are gross, not net:

- *US electricity markets* are gross because financial transmission rights (FTRs) and forward contracts reference ahead prices – not real-time (RT) prices – meaning that ahead market participation is needed to manage basis risks between ahead and RT prices[32]; and
- *The Victorian gas market* is gross because its ahead markets are physical (tied into the operational schedules) and therefore necessarily gross: just as the NEM RT market is physical and gross[33].

On the other hand, voluntary financial ahead markets in the NEM will necessarily be net because market participants have – and are envisaged to continue to have – forward contracts (ie financial derivative contracts referencing RT prices) covering a majority of their physical positions. Since the ahead market trades similar derivatives, market participants cannot and will not trade "gross" in these markets, since doing so would involve buying or selling – in aggregate – physical positions twice over[34].

In the "widget" example in the Market Reform paper[35], this problem is mysteriously overlooked. The paper notes that "the widget maker in question has a contract position to cover for supply widgets" but, nevertheless, it offers all of its physical production capacity into the illustrative market. Depending upon how this market clears, it may now have sold twice its production capacity. This would clearly be commercially nonsensical. On the other hand, if the widget maker were only able to offer the unsold part of its capacity into this ahead market, the example would not work, because the start-up costs etc referred to inherently relate to *total* production.

The implied assumption of gross participation also lies behind some aspects of the "strawman" described in the Market Reform paper: for example

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[29] in the Market Reform paper: the "widget" example on pp14-15; the three-part bids discussed on p22; the operational and network constraints, p23; the intraday market, p24; that PD bids reflect "ahead market schedules",p24; that the UCS would be a "backstop measure" to the ahead market, p 24; that "ahead market participants who follow their ahead market schedule exactly will be settled at the ahead market price"; the demand response example, pp25-27

[30] eg p24, Market Reform paper, ESB paper p83

[31] for example, it is not really true to say that generators bid their "forward contract schedules" into PD today, although obviously their bidding strategies reflect their forward position

[32] there is also an important "wrinkle" in these ahead markets, whereby generators submitting three-part bids are entitled to "make good" payments to cover their start-up costs, but only if they actually run in accordance with the ahead market schedule. This is a physical element in an otherwise financial market, and requires generators to make physical bids. However, in the strawman in the Market Reform paper, it is suggested that these make-good payments would *not* be included in the ESB's design (p25)

[33] and, unlike gas, electricity does not flow ahead of delivery, so there is no comparable physical ahead electricity market

[34] For example, a 500MW generator might sell 400MW of forward contracts. It might then offer, say, another 100MW in the ahead market. But it will certainly not offer 500MW, because it might then sell, in aggregate, 900MW of derivatives, to be backed by a 500MW unit.

[35] pp14-15

- *Three-part bids*: the ahead market scheduler co-optimises start-up costs with production value, but this relies on entire physical units being bid into the ahead market.
- *Network constraints*: the strawman would incorporate network constraints, similar to the current PD engine, but these could only plausibly bind if ahead participation is substantially gross[36].

There are only two ways to reconcile this fundamental inconsistency:

- Design the ahead market so participation is gross: this does not necessarily mean that it becomes legally mandatory, but it would need at least to be so strongly incentivized that participation becomes *de facto* imperative; or
- Give up on the idea of an ahead market as a scheduling mechanism (it could still operate as a hedging platform) and, instead, identify any reforms that are needed to PD to ensure that it can continue to effectively fulfil that role.

As discussed in the previous section, the second path is preferred. However, there are some hints that the ESB could be contemplating – or perhaps unconsciously following – the first path:

- Because network constraints[37] are unlikely to bind in a net ahead market, so ahead participants might get priority access, over RT market participants, to scarce network capacity: how this plays out would depend upon whether COGATI nodal pricing is implemented in the RT and ahead markets;
- An administered "demand curve"[38] through which AEMO bids for market AS in the ahead market, might leave it with little left to purchase in the RT market: so AS suppliers would need to participate in the ahead market[39]
- FTRs issued under COGATI might reference ahead prices[40] (as they do in US markets):
- It might be arranged for forward contracts currently referencing RT prices to be administratively migrated to ahead-referencing contracts[41].

Whilst these design elements might help an ahead market to become gross, they also inevitably undermine the completeness and effectiveness of the RT market, as well as disrupting forward markets and contracts.

A third pathway that is logically possible is for forward contracts to migrate over time, voluntarily and organically, to become ahead-referencing. Ahead market participation would then grow correspondingly until, like the US markets, it is sufficiently gross to allow some scheduling effectiveness. However, as discussed in our June paper[42], such a trajectory seems highly unlikely, for a couple of reasons. Firstly, generically, the importance of liquidity means that established markets tend to have a stranglehold which new markets find it hard to break[43]. Secondly, given the uncertainties remaining at the day-ahead stage, there will always be a need to manage spot price risks, which ahead contracts alone cannot do. And trading forward against *both* markets seems to create unnecessary complexity that market participants would likely choose to avoid.

[36] in any case, since the ahead market is financial, participants could simply bid at the RRN. Bidding at nodes would only be needed if nodal energy pricing is implemented under COGATI.
[37] Market Reform paper, p23
[38] Market Reform paper, p16
[39] clearly the decision as to how to split MAS purchases between the ahead and RT markets is a commercial one and it is difficult to see how this could be dictated by demand curves set administratively by AEMO or the AER. But one could expect that risk aversion would naturally lead AEMO to seek to procure the majority of its needs in the ahead market.
[40] Market Reform paper, p25. Note that this is a suggestion emanating from the Ahead Markets MDI, *not* the COGATI MDI.
[41] Market Reform paper, p25
[42] section 4.2.12
[43] indeed, this is probably a major reason – albeit in the opposite direction – as to why participation in US ahead markets is so high: because these were generally the original markets, with RT markets developed later.

In any case, given that its scheduling effectiveness *requires* that the ahead market is gross, it would be unwise to rely on this migration occurring spontaneously.

3.5 Conclusions

The ahead market cannot be an effective scheduler unless it attracts a substantial majority of the physical market to participate. But this is unlikely to happen unless the ahead market is designed in a way that makes participation imperative, if not mandatory. That would create substantial disruption to existing markets and cause participants to incur substantial costs, complexity and risks. And all for a putative scheduling role that is unlikely to be superior to a reformed PD process that requires none of these things.

4 THE UCS SCHEDULING PRINCIPLES REMAIN UNCLEAR

4.1 SUMMARY

The roles and objectives of AEMO in “intervening” in the market to schedule Non-market Ancillary Service (NMAS) and directions are well established in the current NEM design and nothing being proposed under the ESS MDI appears likely to change these fundamentally. It is not clear whether, under its UCS process, the ESB is proposing to change these scheduling principles, or just to develop tools to achieve the *existing* principles more effectively. It would be helpful for this to be clarified.

4.2 WHAT OUR JUNE PAPER SAYS

Coordination between AEMO and the market would be improved if AEMO’s scheduling objectives were clarified, leading to greater transparency and predictability of AEMO’s actions. AEMO has the twin objectives of, firstly, maintaining system security and reliability whilst, secondly, minimizing the costs of its interventions: both the direct costs (payments made under contracts or directions compensation) and the indirect costs imposed on affected market participants.

A distinction should be drawn here between *spot-priced services* and other services. If the insecurity is caused by the shortage of a spot market service, the price of that service would be set at the market price cap, reflecting that scarcity. Those high prices should encourage greater supply of this service to be offered into PD, hopefully removing the supply gap and associated insecurity. Thus, AEMO should have the objective here of leaving intervention as *late* as possible, to give time for the market to respond and remove the need for AEMO intervention.

On the other hand, if the insecurity is due to a shortfall in *non-spot-priced services*, there will be no such price signal and so little to be gained by AEMO waiting. The market is *never* going to respond, because there is no price for it to respond to. In this case, the objective should be to minimize the cost of intervention, and so to intervene early if this allows AEMO to reduce the cost of intervention.

The UCS is essentially a decision support tool that AEMO would use when scheduling its intervention tools and resources to ensure system security. The scope of the UCS process is quite similar to what AEMO does currently. However, the uncertainty over the objective function remains the “devil in the detail”. A key concern is that the AEMO scheduling might unnecessarily interfere with – and even over-ride – scheduling decisions made by the market. The risk is that AEMO prefers its own schedule and uses it intervention powers to over-ride [the market’s schedule]. Of course, its ability to do this will depend upon how these powers are described and delineated.

4.3 WHAT THE RECENT ESB PAPERS SAY

"The UCS process is based on an analytical tool that seeks to give AEMO an enhanced ability to identify and address security and reliability shortfalls in the operational pre-dispatch timeframe." (P80)

"The UCS would utilise data and information provided by AEMO and market participants regarding technical requirements and attendant costs to be able to identify the least-cost intervention, where required" (P81)

"The UCS would be run regularly with results published. Where the UCS has identified a potential shortfall in a system requirement, this will be indicated to the market, providing time for the market to respond, prior to AEMO intervening, as per current practice." (P81)

"The UCS would use this optimisation when an adjustment to the unit commitment indicated in the pre-dispatch is required to address a system requirement, including an out-of-market commitment or to schedule a resource to provide a contracted system service. Even with a UCS in place, the principles of self-commitment will be followed with the commitment indicated in pre-dispatch the starting point. The UCS will not be used to override the self-commitment of participants unless required where there are *potential shortfalls* of services." (p10) [my emphasis]

4.4 DISCUSSION

The proposed UCS performs two distinct scheduling roles:

- scheduling of NMAS contracts[44]
- scheduling of directions.

These two processes already exist in the NEM. The Rules provide principles that AEMO must follow and AEMO has developed operating procedures in accordance with these principles. It is not clear from the latest description of the UCS whether:

- the UCS is simply a new, more sophisticated tool to aid AEMO in carrying out these processes in accordance with the existing principles; or
- it is proposed to change these underlying principles[45].

Given that the post-2025 project is concerned with identifying fundamental and strategic reforms to the existing NEM design, one would expect it to be the latter[46]. However, if this is the case, one would hope to see a systematic examination of the existing principles: identifying potential issues arising with these as new ESSs are introduced, and presenting options for changing the principles. None of this is discussed in the consultation papers.

On the other hand, if the aim is simply to develop better tools for scheduling under existing principles, one would still expect these principles – and the associated operating procedures – to be examined, to inform the required UCS functionality. But such discussion is also missing from the consultation papers.

Currently, the scheduling of NMAS and of directions operate under quite different principles:

- AEMO may schedule NMAS when required to maintain system security and reliability; or to maintain or increase transmission capacity so as to maximise *market benefit*[47]*;*

[44] although it is unclear whether it would continue to perform this role in options 2 and 3, where there is an ahead market for ESS, as discussed in the next section

[45] it is worth noting that the ESS MDI is not recommending any fundamental changes to the categorization of system services as market or non-market ancillary services. So whilst there may be new NMAS in the future, the existing NMAS scheduling principles could just be applied, unchanged, to the new services

[46] After all, one would expect AEMO anyway to continuously be reviewing its systems and processes to better perform its operational obligations under the Rules, without needing to be prompted by the ESB

[47] Rule 3.11.6(a)

- AEMO may schedule directions where required to maintain system security and reliability, and endeavour to minimise any *cost* related to directions and associated compensation[48].

The first principle requires AEMO to not just schedule the minimum amount of NMAS that is required to ensure system security, but also any additional *economic* amount that provides net market benefit. The consultation papers appear not to consider the latter or include it in the proposed UCS functionality, although this might just be a matter of semantics around the meaning of a service "shortfall".

The distinction between "market benefit" and "cost" across the two principles is critical. In its operating procedures, AEMO implicitly interprets the former to relate to offer prices[49] (and contract prices for the NMAS contract) and the latter to the economic costs of operating (to which the compensation procedures refer). Now any scheduling algorithm – however simple or sophisticated – must operate in accordance with an "objective function" which is to be minimized or maximized. Clearly the current principles require two quite different objective functions – based on offers or costs – depending upon whether NMAS or directions are being scheduled. UCS could potentially operate with either objective function, but not both at the same time! So scheduling of NMAS and directions would, at the minimum, require separate runs of the UCS. Although it is not entirely clear from the Rules principles, one would expect the NMAS scheduling to be run first, to see if any security issue can be resolved without having to resort to directions. The directions scheduling would only take place if the security issue remained unresolved[50].

This may seem to be getting into unnecessary detail. However, the concern is that if the UCS is not operated in accordance with existing principles – whether inadvertently or as a conscious decision to change these principles – it could involve a substantial increase in the degree to which AEMO intervenes in the market[51], as was foreshadowed in our June paper.

[48] Rule 4.8.9
[49] AEMO has recently undertaken a review of its NSCAS procedures. The review considered and addressed many of the issues discussed here. It is surprising that the ESB not acknowledged or drawn from that review.
[50] for example, scheduling of additional units by AEMO under a system strength NMAS contract might increase the amount of non-synchronous generation that can be dispatched within the secure envelope and this might then resolve an energy shortfall that had previously been identified in PD
[51] or, possibly, *decrease* if the UCS does not dispatch economic levels of NMAS, as discussed above

The other aspect of UCS is how it interacts with PD. Our June paper emphasizes the importance of AEMO operating to the same "good faith" obligations as market participants; that is, to signal their bidding *intentions* as early as possible through PD bids and rebids. For AEMO, this would encompass AEMO's intentions to schedule NMAS and/or directions, and provide details of those intentions: plant, timing etc. It appears, from Figure 2 in the Market Reform paper, that this is what the ESB intends, which is encouraging.

4.5 CONCLUSIONS

It would be helpful for the ESB to clarify whether it is recommending that the principles that currently guide the scheduling of NMAS and directions should be changed and, if so, why and how. There is no explicit suggestion that it is recommending this but, on the other hand, the descriptions of the UCS's functionality and operation in the consultation papers do not seem to conform with the existing principles.

Caution should be used in proposing any changes, since these might lead to an unnecessary and detrimental increase in the level of AEMO intervention in the market.

5 THE AHEAD MARKET SHOULD NOT SCHEDULE NON-MARKET ANCILLARY SERVICES

5.1 SUMMARY

The consultation paper suggests that NMAS could be procured at the ahead stage and that this procurement could be incorporated into the ahead market. The opportunity to co-optimise the scheduling of *all* energy ESS on a single platform might appear superficially attractive, but would in fact be unnecessary, impractical and deleterious. Unnecessary, because the PD process already allows for such co-optimisation through its decentralized and iterated architecture. Impractical, because it will not be possible to schedule and cooptimise NMAS in a single algorithm: if it were, they could be incorporated into the NEMDE algorithm as *market* AS. Deleterious, because the volatility and uncertainty of ahead procurement would deter investment in NMAS production capacity.

Instead, NMAS should be procured using term contracts (as now) and scheduled by AEMO using the UCS in accordance with existing principles.

5.2 WHAT OUR JUNE PAPER SAYS

It would be possible to trade system services in a physical ahead market *only*: ie with no associated spot market trading at all. Essentially, this is a particular form of contract market, where the tendering process for the contracts takes place at the ahead stage through some form of auction. A usual non-market AS contract would typically provide for AEMO to be able to call upon the service to be delivered in an ahead timeframe: whether one day or one hour before real-time, say. With the ahead-market AS, AEMO would know how much it needed to procure and so the obligation for physical delivery would be implied.

To introduce such an ahead market, the new system service would need to be incorporated into the ahead market clearing engine using constraints similar to those required by NEMDE in dispatch. There would also need to be a reasonable level of competition in supply of this service to ensure value-for-money for those who would bear the eventual cost of these services.

These are similar to the requirements for introducing the new system service into the spot market. So any new service that could be introduced into an ahead market could also be introduced into a spot market [as a *market* ancillary service]. A spot market would give the additional advantage of being able to adjust the amounts procured in the light of new information arising since the ahead market cleared. So, whilst it is possible that an ahead market in a new system service might be a *complement* to a spot market in that service, it is implausible that it could be an *alternative* to a spot market.

5.3 What the recent ESB Papers say

"The ESB is also considering approaches for voluntary, financial ahead markets to procure and/or trade system services, including those that may not have a real-time market" (P74)

"For services that do not have a real-time spot market, an alternative design may be required for the settlement of any deviation from an ahead schedule given there is not a clear reference price. An option could be to expose these participants to the cost of any action required to fill the resulting gap or to apply penalties under the contract terms and conditions.

The UCS would also be a part of this option as a backstop measure for the system operator if there are any system requirement gaps that are not being met by the market but could be addressed by additional generating units online." (P82)

5.4 Discussion

In the UCS-only option 1, NMAS would be scheduled by the UCS, as discussed in the previous section. However, in the options that include a voluntary ahead market[52], the consultation paper considers the possibility that NMAS would be scheduled through the ahead market.

There is some logic in aiming to schedule *all* services (energy, MAS and NMAS) using a common platform, since this maximises the opportunity to co-optimise the schedule across all of these services. However, there are three fundamental flaws with this. Firstly, the practical difficulty of developing the scheduling algorithm that is able to do this. For illustration, consider how this might be done for system strength services where, as now, NEMDE constraints depend upon the combination of synchronous units that are committed. Incorporating this into a centrally-committing scheduling black box goes far beyond the current state-of-the-art in scheduling algorithms. Again, there is an "assume a can opener" mindset here.

Secondly, the problem discussed in section 3, that a voluntary ahead market is net and cannot sensibly schedule against gross transmission constraints in the way that a conventional scheduler would.

Thirdly, as discussed in our June paper, there are some fundamental disadvantages in deciding to procure NMAS day-ahead, rather than through term contracts:

- There may be inadequate competition to get value-for-money through an auction process;
- The volatility of day-ahead prices may provide insufficient certainty for investment (or postponed disinvestment) in NMAS capacity

On the other hand, if it *were* feasible to co-optimise a NMAS in a scheduler, to create competition in an auction and to provide investment signals through a floating price, it is likely that this service could instead be procured in the RT market; ie it should be considered a market ancillary service, not a *non*-market AS[53].

The consultation papers also describe a possible halfway house, whereby the NMAS is procured through a term contract that requires that the seller then participates in the ahead market under specified conditions: eg with a fixed offer price. In this context, the ahead market is acting purely as a scheduler for NMAS, not as a trading/hedging platform. Given that the ahead market's hedging functionality appears to be the only area where it is superior to a pure scheduler (ie UCS interacting with PD), this seems like using the wrong tool for the job.

In any case, the co-optimisation problem is best solved through iteration, as occurs currently through the PD process. An illustration of how this might work for system strength scheduling was presented in our

[52] options 2 and 3
[53] note that the ESS MDI has concluded that trading ESS in the RT market is always preferable, where possible

June paper[54]. The architectures proposed in the UCS-only – particularly the interaction and interleaving between the UCS and PD engines[55] – suggest that such iteration is envisaged in the UCS-only option.

On the other hand, it is unclear how exactly the *three* processes of UCS, PD and ahead market might interact and iterate under the consultation paper's options 2 or 3. A key issue here is whether – and if so how often – the ahead market repeats. There is a discussion of a possible "intraday" market in the Market Reform paper[56]. However, there are practical difficulties associated with multiple runs of the ahead market, that do not arise with PD. Firstly, of course, the transaction costs – and associated energy trading practicalities – of transacting various quantities in different markets and different prices. Secondly, and more seriously conceptually, the problem that the net day-ahead market becomes a "net-net" market in subsequent stages. That is to say:

- the first ahead clearing will be driven by the difference between the physical RT position that was forecast at the time that forward contracts were struck, and the forecast at the day-ahead stage;
- the next ahead clearing will be driven by the amount by which this physical forecast has *changed* since the prior clearing; which will be minimal if there are many repeated clearings.
- And so on.

Thus even if the first clearing stage were to have high participation[57], subsequent stages would be very much "net"[58].For example, consider a portfolio generator, who had forecast 2000MW, say, of physical output at the time that forward contracts were sold[59] and so sells 2000MW of forward contracts. By the day-ahead stage, it expects to produce 2200MW (eg because the forecast windspeed is higher than typical) and so can offer 200MW to the day-ahead market. By the time of a second clearing stage occurring 30 minutes later, say, this forecast has changed to 2230MW. So it can offer only another 30MW[60]. And after another 30 minutes, it has reduced down to 2220MW, say, so 10MW might be *bought back*. And so on.

In summary, it would seem impractical to arrange for the multiple market iterations that would be required for scheduling of market and non-market ancillary services to converge to a co-optimal solution. In contrast, PD is non-transactional and is "gross" in every stage because of the "good faith" obligation tying it to physical dispatch. So these issues do not arise with PD iteration[61].

5.5 CONCLUSIONS

The ESB is suggesting that NMAS might be scheduled (and traded) in the ahead market under options 2 and 3, rather than scheduled by the UCS. It is implausible that this could occur, due to the difficulties of designing a scheduler sophisticated enough to co-optimise between market and non-market ancillary services and the impossibility anyway of co-optimising in a net market.

It is recommended that this idea is ruled out. Whether or not there is an ahead market, NMAS should be scheduled and cooptimised through the interaction of PD and UCS, as is proposed under option 1.

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[54] section 3.4.4
[55] Figures 2 in the Market Reform paper
[56] p24
[57] perhaps because of design elements discussed in section xxx
[58] A plausible alternative model of multistage settlement is where the derivatives purchased in an ahead market stage refer to the price in the *next* ahead stage. For example, suppose there are two ahead stages: day-ahead and intra-day. In the above example, the generator could still offer 200MW into the ahead stage. Assuming this is cleared, in then has to offer 200MW into the intraday, simply to "defend" its forward position in this market. It could offer an additional 20MW, due to the higher forecast output, so now offer 220MW in total. This model means that once a participant has a position in one ahead market, it then has to defend this position in all subsequent stages, progressively rolling the position through to real-time, where it is defended by physical output.
[59] with appropriate prudence to manage risks around this
[60] assuming that its earlier ahead market offer was fully cleared
[61] as discussed in our June paper, (in section 3.4.6), with the development of autobidders, PD could plausibly be iterated as frequently as the computer runtime allows: eg every minute.

6 THE VALUE OF AHEAD HEDGING IS LOW

6.1 SUMMARY

The one thing that an ahead market can do that PD cannot is allow market participants to hedge any residual exposure to the RT market that they identify at the ahead stage. But the value of such hedging is likely to be low and be far outweighed by the costs of developing and operating an ahead market.

6.2 WHAT OUR JUNE PAPER SAYS

An ahead market might be a facility for a generator to hedge some risks associated with scheduling decisions that rely on PD forecasts that may turn out to be inaccurate. For example, a generator might commit an additional marginal unit on the basis that its costs would be covered by the PD prices, but may end up losing money if spot prices turn out lower. Similar risks might exist for a retailer calling on a customer to manage its demand on the basis of high PD prices.

An ahead market could plausibly hedge such risks. However, the magnitude of the risks that are being hedged seem likely to be quite modest in both relative and absolute terms. Whilst spot prices are volatile, much of this volatility is due to variations in factors (eg weather) that are already known with some degree of certainty at the day-ahead stage and would be reflected in the ahead price. Variations between ahead and spot prices will be relatively small, reflecting only the residual uncertainty at the ahead stage. Furthermore, the exposure is only on a small part of the overall portfolio. So, for a generator, such risk is likely to be in the noise level. Similarly, for a retailer looking to hedge the risks associated with calling demand response, the risks will be relatively small.

There is also an implicit assumption here that ahead trades can be undertaken at close to *fair value*: that is to say, the seller or buyer is not giving up too much expected profit for the sake of reducing its risk. In a liquid market (eg involving the participation of non-physical speculators), trading at fair value is plausible, due to the opportunity to arbitrage away any substantial and consistent differences between ahead price and fair value. However, if the market is thin, any significant offer is liable to pull the market price below fair value and the hedging benefits of the trade are more than offset by the cost of selling at a discount. Liquidity is, unfortunately, self-fulfilling. If traders don't expect to get value in the market, there will be less trading and liquidity and so value will fall further.

Therefore, it seems unlikely that a financial ahead market could offer significant hedging opportunities and value for market participants.

6.3 What the recent ESB Papers say

"An ahead mechanism could provide market participants an additional mechanism (in addition to the contract market) to manage risk and maximise value". (p79)

"The commercial risks presented by these [DR] barriers [being long notice time, inflexible operation, uncertain value received, coordinating with distribution] cannot be fully hedged by participation in the forward contracts market. Consequently, the ESB has received feedback from some demand response providers that a greater level of certainty over the commercial returns ahead of time would improve the ability and willingness of some consumers to make their load flexible." (Market Reform paper p2)

"an ahead mechanism presents an opportunity for participants to fine-tune their hedge position against the expected physical conditions closer to the day, and co-ordinate their participation in the electricity market with their activities across other sectors. While the AEMC recently made a Rule change determination not to progress with the Short Term Forward Market Rule Change1 to introduce a platform for short term energy trading, the potential presented and examined under this initiative differs as it is considers the management of system services and co-ordination of resources in the dispatch timeframe." (Market Reform paper p2)

6.4 Discussion

Hedging is a key aspect of the ahead market in that it is something that only an ahead market (in some form) can provide. Other alternatives, such as the status quo, PD reform or UCS-only cannot provide this hedging functionality[62]. The ESB appears to consider this hedging aspect significant, if not critical. The consultation papers do not attempt to quantify its value, but provide an illustrative example, discussed below.

The value of ahead hedging is constrained by 4 factors:

- The materiality of the unhedged risk[63];
- The design of the ahead market: ie in what products can be traded;
- The liquidity of the ahead market: whether market participants can purchase or sell what they need at a price reflecting fair value; and
- Transaction costs.

Whilst the ESB papers notes generically the potential value of ahead hedging, there is only one attempt to quantify this: a detailed illustrative example of a factory owner using the ahead market to hedge the value of demand response (DR)[64]. It is useful to consider this example further.

In the example, a factory has the production flexibility to shift some of its load from the morning peak to the afternoon trough, given sufficient notice. Output is maintained, but overall load is increased slightly. Thus the shift only makes commercial sense if there is a sufficient spread between the RT prices over these two periods. Prices are uncertain at the ahead time when the decision must be taken, leaving some risk that a shift – decided based on forecast RT prices - will turn out to be unprofitable.

Notable in this example is that the factory owner is, apparently, purchasing its power at RT prices: ie direct from the wholesale market rather than via a retailer. This, of course, entails taking on a large amount of risk, and it seems implausible that any factory would do this whilst, at the same time, worrying about the relatively minor risk associated with making the DR decision described.

A more realistic example would be that the factory owner has arrange to hedge its normal load profile. This might be done at the wholesale level – eg using a PPA – or by negotiating an appropriate retail

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[62] although, of course, nor do they prevent market participants setting up some form of ahead market themselves, since current Rules do not prohibit or discourage this
[63] assuming that RT market risks are primarily hedged, as now, through forward trading and portfolio scheduling
[64] pp25-27, Market Reform paper

contract. But in engaging with the market in this way, why wouldn't it at the same time negotiate terms that allow it to somehow pass on or share the DR risks described in this example?

Of course, this DR area has been contentious for some time. It has been frequently asserted that there has been a market failure here: that customers are unable to obtain satisfactory retail contracts that appropriately capture the value of their DR. But if customers are unable to satisfactorily negotiate a term contract, what is the likelihood of them obtaining something equivalent in the instantaneous clearing of an ahead market?

To hedge in the ahead market, the factory owner has to find a counterparty. The ahead market is voluntary and net; liquidity is certainly not guaranteed. The factor owner is hoping to find – in a short space of time – a counterparty or group of counterparties with a similar – or more pessimistic – view of the RT price spread and the exact same timing of long and short positions. It is notable that, even after 20 years of operation, forward markets do not trade contract profiles with this degree of complexity and specificity. A lack of liquidity will mean that the hedge purchase by the factory will be more expensive – if available at all – and this will erode the expected profitability of the DR action. The available hedges might simply exchange an uncertain profit for a certain loss.

Compare this with the alternative of the DR being sold and hedged using a retailer. A DR component would be included in the retail contract, whereby the retailer rather than the customer would bear the RT price risk. Typical forms of DR contract allow the retailer to decide when to call on the DR: perhaps for a specified number of times per year; perhaps for a fixed payment to cover the customer's DR costs.

Of course, this just passes the problem to the retailer, who still faces the risk of risk of calling on DR that turns out to be unprofitable. But because a retailer or gentailer will have a portfolio of customers or generating plant, DR risks can be managed as part of that portfolio. Indeed, the retailer may use the DR contract as a hedge against RT prices[65], so the DR call might not create new risk (to be hedged in the ahead market) but instead actually *reduces* risk. Alternatively, a gentailer might use the DR call as an alternative to committing a peaking generator say. In this instance, the gentailer has – in effect – traded a day-ahead hedge between its retail and generation arms. Put another way, a portfolio generator or retailer has an immediate counterparty in its own private ahead market: itself.

[65] eg because it has as short portfolio position due to higher than usual customer demand

This raises a key point. In a sense, an ahead market is operating already, through the PD process. But this market only trades “shadow transactions” within each MP portfolio. So, for example, a generator might hedge an anticipated shortfall of output from its wind generation by starting up an additional mid-merit unit. Or a retailer, seeing higher than usual demand – coupled with anticipated high prices – calls on its DR contracts. These “trades” are finessed through the iterations of the PD process.

True, the PD platform does not allow for actual transactions *between* companies. But how many of these are actually required or desired, given the inevitable transactions costs and the spreads that would be payable in an illiquid market? The lack of enthusiasm for a STFM suggests not many.

6.5 CONCLUSIONS

Conceptually, an ahead market could allow participants to hedge some of the day-ahead risks associated with committing generation and DR in advance of real-time, when RT prices are still uncertain. In practice, the magnitude of these risks will be relatively small and the difficulty and costs of finding matching counterparties will be high. To the extent there are risks, these can be – and are – already managed on a portfolio basis by large retailers and gentailers.

So the value of this hedging is likely to be modest and unlikely to justify the substantial costs and disruption associated with implementing an ahead market in the NEM – even a voluntary one.

7 OVERALL CONCLUSIONS

7.1 OVERVIEW

Our June paper concluded that the post-2025 review needed to clear three "hurdles" to establish a case for introducing ahead markets into the NEM design:

- The issues to be addressed need to be real and material;
- Ahead markets must be able to address those issues; and
- Alternative approaches to addressing the issues must be explored and then shown to be less effective.

The review's progress since our June paper can be measured by the extent that it has satisfactorily addressed these criteria. These are considered in turn below.

7.2 ISSUE TO BE ADDRESSED

The consultation paper expresses continuing concerns around the scheduling effectiveness of the current pre-dispatch process in the light of changes expected during the energy transition: new technologies, new ancillary services and greater uncertainty in supply and demand, largely engendered by greater reliance on weather-dependent renewables.

Our June paper explored ways to frame these concerns: for example, whether the iterative pre-dispatch "mega-algorithm" might become unstable, or fail to track and respond to sudden changes in conditions occurring close to real-time. These frailties are plausible but also highly technical, depending upon complex interactions between pre-dispatch participants and the core pre-dispatch scheduling engine. This framing might have provided a basis for the review to better explore and explain the concerns. However, this opportunity has not been taken, and the rationale behind the concerns remains opaque.

7.3 AHEAD MARKETS MUST ADDRESS THESE ISSUES

An effective scheduler must be gross and physical, and PD has these qualities. The ahead markets proposed in the consultation paper are voluntary – and so likely to be net – and financial. This makes it impossible for the ahead market to perform a scheduling role. Logically, an ahead market might, nevertheless, be *complementary* to PD, enhancing scheduling without being a scheduler *per se*. However, the consultation paper does not discuss or explain such potential synergies. Indeed, it is equally plausible that the introduction of an ahead market might degrade scheduling effectiveness. The case for ahead markets remains to be made.

7.4 ALTERNATIVE OPTIONS MUST BE INVESTIGATED

Since the ESB continues to hold concerns that PD performance may deteriorate in the future, an obvious starting point is to identify and evaluate potential changes to this process. Our June paper described some possible reforms but there are doubtless many others. But the ESB has still not explored such possibilities and focuses instead on the introduction of an ahead market operating in parallel alongside the existing (and unchanged) PD.

The post-2025 review is an opportunity to be creative and adventurous in considering a wide range of possible design options to address future NEM challenges. But, in the area of scheduling, the ESB appears to have become attached to a rather tired and anachronistic concept, to the exclusion of other possibilities.

7.5 NEXT STEPS

The time available to complete the post-2025 review is fast running out, but the review is no closer to properly analysing and explaining concerns around future scheduling effectiveness, let alone identifying a plausible market design to address these. The ahead market is a conceptual dead end; it has no relevance to the NEM. The review's resources should urgently be redeployed to investigating feasible and promising design options, that build on the NEM's existing strengths rather than ignoring them. The quest for an ahead market should be abandoned.

APPENDIX: ANSWERS TO CONSULTATION QUESTIONS

Q1: The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?

The additional option that should be considered is “UCS + enhanced PD process”. Potential PD enhancements should be identified and developed through the usual market design process of (a) describing and understanding the current design (b) identifying issues that may arise with PD scheduling efficacy in the light of anticipated changes occurring in the energy transition (c) proposing specific changes to the PD design to address these issues (d) evaluating the costs and benefits of these changes. Many of the concepts introduced in the ahead market design (eg intertemporal linking etc) could be considered for the PD process.

The proposed ahead markets are not fit for purpose, because they are voluntary and therefore “net”: representing only a portion (likely a small portion) of the physical market. Effective scheduling requires visibility of a large part of the market, as PD has. This is not to say that the ahead market should be made mandatory or designed in a way that makes participation imperative. That would substantially disrupt market design and operation, and undermine spot market effectiveness, for no obvious gain. Rather, it should be recognised that ahead markets can operate in this way only in markets that are traditionally “gross” (high levels of participation) by design or tradition. US electricity markets and the Victorian gas markets are examples of such markets. The NEM is not.

Q2: The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?

If AEMO considers that the UCS would improve the efficacy of its existing roles in scheduling non-market ancillary services and directions, in accordance with the current Rules, then it should be developing this tool already. It does not need to await the findings of the post-2025 review.

A key factor is that any UCS developed in the short-term should operate in accordance with existing scheduling principles and objectives – as set out in the current Rules. That is not to say that these principles could not be reviewed, but that should be done separately to the development of the UCS as a functional application. If it is decided to change the Rules, the UCS functionality would need to change accordingly.

It is also key that AEMO – in using UCS – interacts closely with PD, following the same “good faith” obligations (ie timely notification of intentions) as generators are subject to today. Interaction and iteration between UCS and PD will ensure that the non-market scheduling being undertaken by AEMO is co-optimised effectively with the market scheduling being done by market participants.

Q3: The difference between actual and forecast residual demand leading up to real-time dispatch has been far more stable in the last decade than the difference between actual and forecast prices ($MWh) leading up to real-time dispatch. What do you consider the drivers of this may be?

It should be a core activity of the post-2025 review – and indeed any review of market design – to understand how the market operates under the current design and how this might be impacted by external changes occurring through the energy transition. So it is surprising that this question is only being raised now. These types of questions should have been presented at the outset of this review. It is essential to diagnose and understand existing (or anticipated) problems, before proceeding to look for solutions.

In any case, this analysis begs the questions of whether these larger price differences are indicative of deteriorating scheduling efficiency in PD, whether accurate price forecasting is actually a key objective for the NEM design[66] and, if so, whether performance would be improved by the design changes being proposed.

[66] since, of course, market participants can do their own price forecasting