Scheduling and Ahead Markets

Submission to the ESB Consultation Paper

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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"[1]
- The "Market Reform paper"[2]

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[3]
- Reliability Standard Implementation Guidelines, Medium Term Projected Assessment of System Adequacy (MTPASA) Process Description[4]

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[5] ("our June paper") that the AEC subsequently published and also submitted to the ESB. Because the analysis in that paper was largely generic[6], 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] *Chapter 7*, *Post-2025 Market Design Consultation Paper*, Energy Security Board, September 2020
[2] *Scheduling and Ahead Markets*, Market Reform, undated
[3] *NSCAS Description and Quantity Procedure Review Final Report and Determination*, AEMO, September 2020
[4] *ST PASA Replacement, Functional Requirements*, IES and SW Advisory, 20 May 2020
[5] *Scheduling and Ahead Markets: Design Options for post-2025 NEM*, Creative Energy Consulting, June 2020
[6] although one section was devoted to assessment of the ESB's proposals as they stood at the time

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:

- 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[7]. 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[8], 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.

[7] figures 25 and 26, consultation paper

[8] the ESB's "USB only" Option 1 relies *entirely* on PD for market scheduling

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[9]) 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[10] rather than PD or ahead markets. AEMO's consultants[11] have recommended, in their final report to AEMO, that MTPASA should employ a sophisticated scheduling engine[12]. 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 example, storage operators might use the MTPASA results to inform the storage cycles that they bid into PD[13].

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.

[9] note that the PD engine itself is based on the dispatch engine, which is also a market clearing algorithm
[10] as part of its review of the MTPASA process description. MTPASA operates in the 7-day window ahead of PD
[11] IES and SW consulting
[12] 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
[13] 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[14], 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[15]? 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.

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[14] 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.

[15] 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[16]. 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. "

[16] 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[17] implicitly assume "gross" and physical participation. It also refers at several points to generators bidding their "ahead market schedule"[18] 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[19]. 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[20]; 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[21].

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

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[17] 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

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

[19] 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

[20] 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)

[21] and, unlike gas, electricity does not flow ahead of delivery, so there is no comparable physical ahead electricity 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[22].

In the "widget" example in the Market Reform paper[23], 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

- *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[24].

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[25] 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;

[22] 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.
[23] pp14-15
[24] 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.
[25] Market Reform paper, p23

- An administered “demand curve”[26] 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[27]
- FTRs issued under COGATI might reference ahead prices[28] (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[29].

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[30], 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[31]. 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.

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.

[26] Market Reform paper, p16
[27] 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.
[28] Market Reform paper, p25. Note that this is a suggestion emanating from the Ahead Markets MDI, *not* the COGATI MDI.
[29] Market Reform paper, p25
[30] section 4.2.12
[31] 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.

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[32]
- 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[33].

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[34]. 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.

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[32] 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

[33] 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

[34] 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

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*[35]*;*
- AEMO may schedule directions where required to maintain system security and reliability, and endeavour to minimise any *cost* related to directions and associated compensation[36].

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[37] (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[38].

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[39], as was foreshadowed in our June paper.

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[35] Rule 3.11.6(a)

[36] Rule 4.8.9

[37] 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.

[38] 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

[39] 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[40], 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[41].

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

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 June paper[42]. The architectures proposed in the UCS-only – particularly the interaction and interleaving between the UCS and PD engines[43] – 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[44]. 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[45], subsequent stages would be very much "net"[46].For example, consider a portfolio generator, who had forecast 2000MW, say, of physical output at the time that forward contracts were sold[47] 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

[42] section 3.4.4
[43] Figures 2 in the Market Reform paper
[44] p24
[45] perhaps because of design elements discussed in section xxx
[46] 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.
[47] with appropriate prudence to manage risks around this

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[48]. 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[49].

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.

[48] assuming that its earlier ahead market offer was fully cleared

[49] 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[50]. 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[51];
- 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)[52]. 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

[50] 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
[51] assuming that RT market risks are primarily hedged, as now, through forward trading and portfolio scheduling
[52] pp25-27, Market Reform paper

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 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[53], 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.

[53] 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[54] and, if so, whether performance would be improved by the design changes being proposed.

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