Shell ENERGY

9 June 2021

Dr Kerry Schott AO
Chair
Energy Security Board

Lodged via email: info@esb.org.au

Dear Dr Schott

RE: Post-2025 Market Design Options

Shell Energy Australia Pty Ltd (Shell Energy) welcomes the opportunity to respond to the Energy Security Board's (ESB's) options paper (the Paper) on the mooted post-2025 design of the National Electricity Market (NEM).

About Shell Energy in Australia

Shell Energy is Australia's largest dedicated supplier of business electricity. We deliver business energy solutions and innovation across a portfolio of electricity, gas, environmental products and energy productivity for commercial and industrial customers. The second largest electricity provider to commercial and industrial businesses in Australia[1], we offer integrated solutions and market-leading[2] customer satisfaction, built on industry expertise and personalised relationships. We also operate 662 megawatts of gas-fired peaking power stations in Western Australia and Queensland, supporting the transition to renewables, and are currently developing the 120 megawatt Gangarri solar energy development in Queensland. Shell Energy Australia Pty Ltd and its subsidiaries trade as Shell Energy.

www.shellenergy.com.au

General comments

The National Electricity Market (NEM) is in the midst of an inevitable and ongoing transition, but the market rules and structure are lagging behind the global and societal shift driving the transition. There is an unprecedented level of change needed to position Australia for the economic growth driven by industry and jobs underpinned by greater volumes of cleaner energy. This is a huge opportunity if we get the market design right.

Shell Energy is looking at the long term and the broad fundamentals as it looks to invest in the NEM. Our ability and incentive to invest and grow in this market is conditional. We need stable policy settings, and regulatory change that is well considered, stands up to cost benefit analysis and delivers as intended. The electricity sector, and the NEM itself continue to be the subject of revolving reform and regulation, often with competing and conflicting objectives and direction.

The wave of regulation and reform over the past decade – whether implemented, incoming, repealed or rejected – has not been the primary driver of lower wholesale electricity prices. In reality, prices cycled back down after the market absorbed the short-notice exit of Hazelwood and announcement of Liddell's closure and

[1] By load, based on Shell Energy analysis of publicly available data
[2] Utility Market Intelligence (UMI) survey of large commercial and industrial electricity customers of major electricity retailers, including ERM Power (now known as Shell Energy) by independent research company NTF Group in 2011-2020.

saw committed renewable and storage build. The economic downturn during the COVID-19 pandemic has also contributed. We expect a similar dynamic to occur in response to the recent failure at Callide.

The Post-2025 Options Paper is the latest step in a process that we see is aiming to find stable and long-term solutions to the issues arising from the energy transition underway. Policy and regulatory stability form a critical role in providing an outlook for the market five or more years out, with liquid contract markets also serving as the lifeblood of a well-functioning electricity market that serves customers and our economy well. Tradable and competitive markets, with independent economic regulation, remain the best mechanism to deliver secure, reliable and affordable energy, and product innovation for consumers.

Resource adequacy and aging thermal generator retirement

Shell Energy understands there is anxiety from governments, regulators and energy users about supply, particularly firm capacity as coal assets exit the market.

Yet, the market is already responding and will continue to respond to coal-fired generation exits. The Australian Energy Marker Operator's (AEMO) Generation Information[3] indicates almost 5200 MW of additional committed capacity is coming online, with around half of that coming online by next year. The Paper itself suggests even more capacity will be online by the time of Liddell's exit from the market in 2023-24.[4]

The Paper and recent consultation also give the appearance of zero tolerance for unserved energy. However, historically the market has performed exceptionally well, with the last breach of the reliability standard occurring in 2008-09. Furthermore, over 2008-09 to 2017-18, just 0.3% of outages occurred due to wholesale reliability issues.[5] Overwhelmingly, the major cause of outages over this time was at the distribution level. Measures to improve wholesale reliability will not fix the 95% of outages that occur at a network level. There is a real risk that pursuing costly approaches to enhance NEM wholesale reliability beyond already extremely high levels will lead to higher costs for no noticeable benefits to consumers. Consumers have already paid for "gold plating" of networks and we doubt there is any desire to pay more to increase wholesale reliability beyond the existing extremely high levels.

We can see there may be some benefits to changing the Retailer Reliability Obligation (RRO) to bring greater transparency. Under the right design, a physical certificate-based RRO could provide a long-term signal for new capacity and better value dispatchable capacity. It will be crucial to ensure that smaller and non-vertically integrated retailers are able to access sufficient contracts or certificates to ensure compliance and that consumers aren't paying more for no meaningful benefit to reliability.

Essential system services, scheduling and ahead mechanisms

Shell Energy encourages the ESB to pursue market-based approaches for system services. We note that the Australian Energy Market Commission (AEMC) is driving work on many of the essential system services reforms through rule changes such as fast frequency response, operating reserves, system strength and primary frequency response incentive mechanisms. We consider that the AEMC's work is largely the right process for consideration of these rule changes given the complexity and technical nature of them. Shell Energy has made submissions to the AEMC on several of these rule changes and will continue to do so as draft determinations and other papers are released for comment.

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[3] AEMO, *Generation Information*. Accessed 31 May 2021 from: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

[4] ESB, *Post-2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 14

[5] AEMC Reliability Panel, *The Reliability Standard Fact Sheet*, pp 2. Accessed from: https://www.aemc.gov.au/sites/default/files/2020-03/Reliability%20Standard%20Factsheet.pdf

Shell Energy remains unconvinced of the need for an operating reserve in the NEM. It is entirely unclear how this would change generator behaviour beyond what the existing market settings already do. The presentation on modelling on an operating reserve that was presented to the ESB's Technical Working Group appears to demonstrate this as well, with seemingly little benefit provided by an operating reserve for the scenarios modelled.

Distributed energy resources and demand-side participation

With increasing volumes of behind-the-meter solar PV and battery storage in the NEM, along with the potential for electric vehicles to become a major source of both load and supply, Shell Energy can see real value from more information on these types of resources being made available to the market operator. This could improve both demand forecasting and dispatch outcomes in the NEM.

The proposed scheduled-lite arrangements warrant consideration to bring more distributed energy resources (DER) and demand-side response into the market, especially as this is projected to grow strongly.

Shell Energy is troubled by the seeming re-emergence of the multiple trading relationships (MTR) rule change that the AEMC rejected in 2016, in the Options Paper under the guise of flexible trading arrangements. While the ESB states it "is not considering the previously proposed Multiple Trading Relationship (MTR) changes at this stage", the flexible trading model described are very much akin to the previously rejected MTR rule change.

Adopting a rebranded MTR model called flexible trading arrangements does not solve the issues that existed when the AEMC rejected the rule change. There are huge system costs involved in implementing this change which would be imposed on all consumers for the advantage of a select few.

The soon to be implemented Wholesale Demand Response Mechanism provides a low-cost model to allow for customers to provide demand reduction into the market. The adoption of additional baselines would be a better way to bring more demand-side into the market than the proposed flexible trading arrangements concept.

Transmission and access

The Paper is clear that, "in the long term, the ESB's preferred solution for access reform is to shift to locational marginal pricing and financial transmission rights"[6]. The most significant reforms on the 'transmission and access reform pathway'[7] are being developed with this end goal in mind. In particular, the mooted medium-term access options are "designed to be a stepping-stone towards a longer-term solution [of] locational marginal pricing and financial transmission rights"[8].

Shell Energy is deeply concerned by this approach. An access regime based on locational marginal pricing (LMP) and financial transmission rights (FTR) has been repeatedly and comprehensively rejected by industry and consumer stakeholders[9, 10, 11]. Consistent with this opposition, we consider that progressing medium-term reforms designed to move towards an LMP/FTR regime to be a mistake. We believe that a prudent path forward would be to:

[6] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 89

[7] ibid, pp 91

[8] ibid, pp 83

[9] ERM Power, *RE: Stage 2 REZ consultation*, 12 February 2021. Accessed from: https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/ERM%20Power%20response%20to%20consultation%20paper%20on%20interim%20REZ%20framework.pdf

[10] Stakeholder responses to: AEMC, *Coordination of generation and transmission investment implementation – access and charging*, November 2020. Accessed from: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

[11] Stakeholder responses to: ESB, *Stage 2 REZ Consultation*, February 2021. Accessed from: https://energyministers.gov.au/publications/stage-2-rez-consultation-energy-security-board

1. cease all work on the medium-term, whole-of system reforms designed as a 'stepping-stone' to a long-term LMP/FTR regime
2. over the medium term, engage meaningfully with stakeholders to develop a workable alternative long-term access regime that does not require LMP/FTR
3. in the near term, focus on developing renewable energy zone (REZ) access frameworks.

Point 2 is distinct from the reform process to date, which has largely involved the AEMC/ESB proposing different variations of an LMP/FTR regime, and stakeholders arguing against these proposals. The Paper is an example of this approach – the Congestion Management Model (the option with built-in LMP/FTR) is the cornerstone of three of the five medium-term options. By contrast, the other two options (a locational connection fee and generator transmission use of system charges) are substantially less developed, and are seemingly adjudged less favourably as a result. This approach is suboptimal. Any new access regime should only be chosen after considering the best version of all credible long-term options, rather than comparing the best LMP/FTR-type option with underdeveloped alternatives.

Shell Energy is committed to working constructively with the ESB. To that end, we have provided feedback on each of the Paper's medium-term reforms. We have also outlined a potential long-term access regime by building on the concept of a locational connection fee (see Attachment A). Although our proposed model is still a work in progress, we consider it shows sufficient potential that it cannot be dismissed outright in favour of LMP/FTR. With a consultative development process (see point 2 above) that doesn't treat LMP/FTR as the preferred outcome by default, we believe our proposal could be further improved, or an even better alternative could be developed.

Shell Energy agrees with the ESB that the immediate focus should be on developing REZs. We disagree with the ESB's view that whole-of-system reform is required for REZ access frameworks to deliver benefits to REZ participants and the system more broadly. We consider the ESB's view may lend a false sense of urgency to whole-of-system reforms.

Section 4 of our submission provides additional feedback on the proposed transmission and access reforms, including greater detail on the issues discussed above.

Conclusion

We look forward to continuing to engage with the ESB over the coming months as it delivers its final advice to energy ministers. Stable and certain policy settings are essential to give businesses the confidence they need to invest in the electricity market. Comments on each of the market design initiatives are contained in the submission that follows.

Our Regulatory Affairs team stands ready to discuss and support this submission with your officers to ensure understanding, discuss further and co-develop proposals contained therein.

Please contact me if you would like to discuss this submission further.

Yours sincerely

Greg Joiner
VP Shell Energy Australia

1 Resource adequacy

Shell Energy does not see that wholesale market reliability is a major issue in the NEM. Historically, wholesale reliability has been very strong, with unserved energy a rarity, and the last breach of the reliability standard occurring in 2008-09 under the most extreme power system conditions. Over 2008-09 to 2017-18, just 0.3% of outages occurred due to wholesale reliability issues.[12] Overwhelmingly, the major cause of outages over this time was at the distribution level and while improvements in the loss of supply in the distribution network have also been achieved during this period, this has occurred at significant costs to consumers. Measures to improve overall system reliability through changes to the Retailer Reliability Obligation (RRO) do not address the level of outages at the network level.

We also remind the ESB and governments that no measure can reduce the risk of blackouts to zero. There will always be some risks that cannot be managed or resolved through these changes – extreme weather events can take out transmission lines, generators and transmission networks can fail unexpectedly like the recent outage at Callide C power station and the Calvale switchyard in Queensland. Neither a triggerless RRO nor a physical certificate scheme can guarantee perfect wholesale reliability.

We understand that there is real concern about the potential for wholesale reliability issues to emerge due to the ageing nature of the fleet and as thermal generation exits the market over the coming years with Liddell and Yallourn the next two major power stations due to exit the market. Liddell's exit in 2023-24 is one of the drivers of the 2020 Electricity Statement of Opportunities (ESOO) forecasts of breaches of the interim reliability measure – a stricter reliability measure than the reliability standard – in NSW in 2023-24.

Historically though, AEMO has frequently forecast breaches of the reliability standard several years out only for the reliability gap – a measure of how many MW would be needed to reduce USE to within the reliability standard – to disappear within a few years. There are various reasons for this including AEMO's tendency in previous years to overestimate peak demand and currently, a cautious approach to including new generation projects or network upgrades in its forecasts. While we understand there is a need to be cautious, particularly around planned generation assumptions, we believe that AEMO's conservative approach excludes generation that will almost certainly be built from its reliability forecasts.

If changes are to be made to improve wholesale reliability above the already extremely high level being achieved and forecast, then Shell Energy sees benefits in bringing transparency to these costs. If consumers are to foot the bill for increased wholesale reliability, then they should clearly be able to understand the cost impact of policy changes to achieve this.

1.1 Jurisdictional investment schemes

The ESB has set out a range of options to manage the risks associated with the early exit of thermal generation. Broadly speaking, Shell Energy is comfortable with what has been proposed as a backstop to avoid the impacts of early exit.

Shell Energy supports the aims to find consistency in jurisdictional investment schemes and the principles which the ESB outlines for those schemes. We agree that it is important for generators supported by jurisdictional investment schemes to make decisions based on the spot price at the time of dispatch. Exposure to the spot price can enable better decisions on commitment and de-commitment at times of high or low spot prices. Further, we concur that jurisdictional investment schemes should be structured to incentivise participants to enter into bilateral contracts rather than relying on an underwriting contract with the government. Options contracts are ideal to meet this principle in that they provide the generator with a backstop price if market prices are low, but

[12] AEMC Reliability Panel, *The Reliability Standard Fact Sheet*, pp 2. Accessed from: https://www.aemc.gov.au/sites/default/files/2020-03/Reliability%20Standard%20Factsheet.pdf

provide ample incentives to strike contracts with other market participants in order to secure a higher price. The NSW Electricity Infrastructure Roadmap proposes to use such as approach and as such is a good example of the kind of structure that could be used by other jurisdictions. Entering into contracts can also support liquidity in the contracts market and in the event that these contracts are 'firm' can support retailer to meet their obligations under the RRO.

1.2 Thermal Generator Exit

Shell Energy understands the concerns driving much of the discussion around thermal generator exit. Yet, we are confident that the existing market mechanisms including the Medium Term Projected Assessment of System Adequacy (MTPASA), the Energy Adequacy Assessment Projection (EAAP), the Electricity Statement of Opportunities and the 42-month notice of closure rule, provide sufficient guidance and rigour as to require little in the way of reform, other than to extend the MTPASA reliability assessment from 24 to 36 months. In addition, the Short Term Projected Assessment of System Adequacy (STPASA) provides information closer to real time dispatch to allow adjustments to intra-day and weekend operational decisions. These reliability assessment processes already require substantial detail from generators about their intentions for operation and information about return to service times (where necessary). The introduction of the 42-month notice of closure rule also strongly reduces the likelihood of another short-notice closure like the shutdown of Hazelwood power station, although the risk of unplanned exit of generation due to equipment failure remains.

In addition, we understand the concern that mothballing could be used as a loophole to undermine the 42-month notice of closure period. While we agree this may be a risk, there is a definite challenge in determining whether mothballing is genuine due to prevailing and expected market conditions or an attempt to circumvent the notice of closure rules. Nor would a blanket requirement for a 42 month notice of mothballing be an appropriate response given that commercial conditions can change rapidly, as can plant maintenance requirements. That said, there probably is a case to look more closely at mothballing decisions if the decision increases the risk of breaching the Interim Reliability Measure (IRM) or reliability standard, particularly if that would see the RRO triggered as a result. Such a scenario is far more likely under the proposed 'triggerless' RRO which we will examine later in this submission.

On the issue of how to handle announced exits, Shell Energy cautiously welcomes the proposal to deal with announced exits that may pose unacceptable risks to the energy market. The suggested design of Orderly Exit Management Contracts (OEMC) is a logical one to deal with the concerns about thermal generator exit. We add that it will be important to design these schemes in such a way that they do not incentivise exiting generators to actively seek to secure an OEMC with a state government because it offers a better commercial prospect than the market. Similarly, we warn that there are risks to future investment in the sector if governments seek to use OEMCs to avoid high prices in the spot market. As a retailer we do not wish to see prolonged periods of high prices in the market, yet we understand that times of high prices are necessary to provide the right investment signals for new entrants, particularly in firm dispatchable capacity. As the NEM is an energy-only market, these high-priced periods are critical to allowing generators to recover long-run costs and to demonstrate when and where new investment is needed. Intervention that seeks to dampen prices will likely create the need for more intervention to secure future investment.

1.3 Amendments to the RRO

Shell Energy finds it challenging to be discussing changes to the RRO once again. The RRO entered into force in 2019 following extensive stakeholder consultation. Yet there have been continual reforms enacted and proposed since that time. The South Australian Government implemented a derogation to allow it to unilaterally declare a T-3 trigger almost immediately. While it has declared several T-3 triggers with no AEMO forecast 'reliability gap', no subsequent T-1 reliability gap has been declared either. In addition, the ESB enhanced the reliability standard by adopting the Interim Reliability Measure, allowing for just 0.0006 per cent unserved energy (USE) in any region. Despite this lower standard, AEMO has forecast just one reliability gap period, a T-3 trigger for NSW in 2023-24. Shell Energy considers the reliability gap will be solved by the time the T-1 trigger would need to be made. Again, the ESB is canvassing additional options for reform of the RRO here. Strangely, it appears to Shell Energy that the lack of a wholesale reliability issue in the NEM – highlighted above – is seen by some as a failure of the RRO.

Nonetheless, Shell Energy has examined the proposals for changes to the RRO to improve the investment signals for investment and provides comments on each of the options below.

1.3.1 Triggerless RRO

In 2019 the ESB raised the prospect of removing the T-3 trigger from the RRO process, instead relying solely on a T-1 trigger only. At the time, stakeholders largely rejected this option because the purpose of the T-3 trigger was to signal to the market that more capacity was needed in a region and allow the market to close any forecast reliability gap itself. It also avoided the prospect of retailers being at risk of non-compliance if a generator unexpectedly closed less than three years out, giving the market little time to react to solve the forecast reliability gap. For these reasons, the ESB rejected the T-1 only trigger model at that time.

It is therefore unclear why the ESB has yet again returned to this option. Shell Energy recognises that the ESB has set out a range of potential objectives for reforming the RRO including: supporting longer term investment signals; encouraging commercial risk-taking for investment; avoiding disruption to price signals in the real time market as much as possible; ensuring market participants bear risk for wholesale reliability gaps experienced by customers; sufficient financial incentives or capacity commitments to deliver the physical needs of the power system; and helping ensure new resources are operating in the market when they are needed.

We accept that removing the T-3 trigger would likely be a simple reform compared to implementing a certificate-based RRO, and that in itself is certainly an important consideration. As acknowledged by the ESB, changes to the Market Liquidity Obligation (MLO) would likely be needed as part of a 'triggerless' RRO. We agree that this would be crucial to facilitating this reform, but disagree that looking purely at a liquidity-based trigger would be sufficient.

The current MLO, while a positive development, remains challenging for smaller retailers. This is because obligated parties can meet the requirements by offering calendar year or financial year cap or swap products. Although these products will certainly cover the gap period, it also covers quarters unaffected by the gap period. We recognise that this could be seen as a positive for generators in that they are potentially able to secure revenue for an entire year. Yet, smaller participants can find it challenging to meet the financial requirements in order to carry the costs of 12-month contracts when their only need is probably for a quarter. Given that one of the purposes of the MLO is to ensure liquidity for small participants, it seems to Shell Energy that the current structure probably provides more advantages for larger generators and gentailers than for smaller retailers. Under a triggerless RRO, this distortion will likely be enhanced, as retailers will need to be contracting to higher levels, and there is unlikely to be a gap period defined until the prior year's ESOO around 15 months in advance.

Instead, we recommend that the purpose of the MLO needs to be re-examined under a triggerless RRO. At a minimum, the obligation should be on generators to make contracts available just for the quarter (or quarters) where a reliability gap is forecast when the obligation binds. There may still be a role for a 'trigger' of sorts at T-3 in order to set expectations for when MLO contracts must be made available.

Shell Energy sees that the 'triggerless' RRO option would be more acceptable if there were changes to the MTPASA to ensure that it is extended to 3 years duration. The AEMC's final determination on ERM Power's 2019 rule change proposal to extend the MTPASA to three years was limited to generation availability.[13]

[13] AEMC, *Improving transparency and extending duration of MT PASA, Rule determination*, 20 February 2020

Notwithstanding, AEMO publishes forecast semi-scheduled generation and regional 10% POE and most probable peak demand assessment in the MTPASA for the third year. It is also worth noting that the MTPASA reliability assessment modelling uses the same half-hourly demand and uninterrupted intermittent generation forecast traces utilised in the ESOO reliability assessment modelling, so no additional work is required by AEMO other than to run the MTPASA third year reliability assessment and publish the results.

Shell Energy argues that the lack of the third year of the MTPASA reliability assessment limits the market's ability to make reasonable and sound judgements on wholesale reliability in the 24-36 month period. Extending the MTPASA reliability assessment would provide important and regularly updated guidance to the market about wholesale reliability in the NEM for the full three-year period giving retailers ongoing and strong signals to manage their contracting levels over that time. Extending the MTPASA reliability assessment to three years would facilitate quick assessment of any wholesale reliability issues which occurred due to any seasonal mothballing and provide generator operators with clear signals regarding seasonal mothballing in the event of a major supply side resource failure event. This would improve transparency in the market while maintaining a three-year signal about the potential need for supply-side response (including demand response) to address any forecast reliability gap.

Extending the MTPASA reliability assessment to three years would also allow the trigger for the MLO to be activated for any year where the MTPASA reliability assessment indicated an exceedance of the reliability standard or the IRM. The MLO would be triggered in those years for the months were the MTPASA indicated forecast USE.

1.3.2 Certificate-based RRO

Shell Energy considers that there may be a case to move to a certificate-based RRO, based on physical capacity. However, we caution that our support for this model is severely contingent on a range of design choices. We would be unable to support a certificate-based scheme if it failed to address some of our key concerns such as the main issue that while retailers must buy certificates, generators may sell them. Without an obligation on generators to make certificates available, we consider that this scheme poses unacceptable risks to small and new entrant retailers.

We remain steadfastly opposed to a purely physical RRO, where compliance is based on contracts for physical supply as this would upend the market and destroy contract market liquidity, which underpins efficient retail pricing. It would also impose a significant administrative cost burden on the market as contracts would need to be registered against specific physical assets. Requiring a direct physical link between contracts and generation may destroy volumes in the contract market and therefore make it far more difficult and costly for non-vertically integrated retailers to compete in the electricity retail market. This would have serious impacts on competition and prices for end users.

We understand the ESB is not proposing this model as such. However, Shell Energy is wary given that within two years of the RRO entering into force, changes have already been made. The Interim Reliability Measure was implemented despite the opposition of energy users, consumer groups and retailers and the post-2025 project seems to have been seeking to 'fix' the RRO throughout its process despite a lack of any wholesale reliability event. A certificate-based obligation where certificates are created and traded entirely separate to existing financial contracts is a different matter, and this approach could help to retain contract market liquidity while creating a direct price for firm capacity.

Ultimately, we see there could be an advantage in the certificate-based model as it creates a transparent price for capacity. This will show electricity consumers and the wider market the true cost of complying with the RRO and therefore, the 'cost' of capacity. In theory, when there is sufficient capacity, prices for certificates should be low, and if the supply-demand balance is tight then we would expect prices to rise. Over time, the average price of these certificates should signal when new capacity is needed. Essentially, the value of capacity certificates would be akin to what cap products have historically provided.

We dispute the ESB's assertion that a certificate-based RRO is "is likely to impose increased barriers to retail competition and product innovation than modifying the current RRO"[14]. While we do agree that there are certainly risks to existing and new entrants under either this or the 'triggerless' RRO model, we consider that the 'triggerless' RRO restricts some product offerings. Retail models that use exposure to high prices to drive a consumer response, such as through voluntary demand response, are significantly disadvantaged by the triggerless RRO which will require more or less permanent contracting.

Given that there is no proposed model to respond to as such – we do note and appreciate the ESB's work to identify key questions relating to a certificate-based model – we consider it helpful for us to set out a design of a certificate-based physical RRO that we could support.

Firstly, we believe that the obligation to procure certificates should be ongoing, with compliance checked following a 'trigger' event such as demand exceeding the region's P50 (one-in-two-year) peak demand value as specified in the Electricity Statement of Opportunities (as per the existing RRO), dispatch of the Reliability and Emergency Reserve Trader (RERT) or the issuing of a declared actual Lack of Reserve 2 or 3 (LOR2 or LOR3) notification. Shell Energy considers that if this scheme is to be effective at valuing capacity and signalling the need for new investment, it needs to be a permanent measure rather than a triggered one like the existing RRO.

The Paper rightly sets out the challenge of how to determine who can sell capacity certificates and at what volumes. The ESB appears to believe there are only two approaches – that AEMO would assess how many certificates a generator can sell or that a generator can self-assess . Shell Energy does not support AEMO playing a role in setting the volume of certificates each generator can make available.

At the first instance, we consider that participants themselves are best placed to assess the volume of generator capacity certificates they are able to sell based on their generation facilities' expected reliability. This would be consistent with the self-assessment option proposed. Shell Energy would expect the need for oversight and as such that any approach would require approval by the Australian Energy Regulator (AER) in the same way that the current RRO requires retailers to have their approach to contract firmness also approved by the AER. Similarly, the AER would develop, consult on and issue a guideline or methodology setting out potential compliant methods for calculation of generator capacity certificate limits. In addition, Shell Energy also contends that given the costs involved in determining this, and the potential need for auditors like the current RRO, there should be a backstop approach to the calculation of generator capacity certificate limits that could be used. This would allow smaller participants to use a low-cost, default approach that would not require an auditor or approval by the AER. Again, we consider that this would create a more efficient system that would lower overall costs.

Further, we believe that it is critical for generators to be able to sell generator capacity certificates on a portfolio basis at the regional level. This means that all of a generator's available capacity in a region (i.e. state) can be used to determine its level of capacity certificates that the generator can offer. By allowing for a regional portfolio-level approach, generators can spread the risk of outages across all their generation facilities located within the same region. This means that the risk of an outage at one unit can be covered by units across the state. This should also allow for participants with a portfolio of variable renewable generation to increase what they may be able to sell to the market above what they would otherwise be able to sell if eligibility was assessed on each individual generation facility. This should increase the amount of generation capacity certificates available to the market and produce a more efficient result for consumers, who ultimately will pay for this scheme.

[14] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 26

We also consider a certificate-based model must allow for the inter-regional transfer of electricity, consistent with the existing RRO. Electricity flows across state lines subject to the limits of interconnectors, so it is reasonable for a retailer whose load is in one region to be able to procure generation capacity certificates from another region. As with the current RRO, a participant would have to pair their inter-regional position with the purchase of settlement residue auction units (SRA units) which entitles them to a share of the inter-regional settlement residue. To the extent that the inter-regional transfer is not fully recognised as with the firmness rating in the current RRO, then the participant should be able to split the volume across the two states.

For example, a retailer purchases 200 MW of generation capacity certificates from NSW generators to manage liability in Queensland along with 200 NSW to Queensland SRA units to pair with the certificates. However, if the AER will only allow for 75 per cent of the SRA units to count towards liability in Queensland due to the possibility of lower transfer limits on the NSW to Queensland interconnector, then the retailer should be able to use the remaining 50 MW of NSW generation capacity certificates to manage their liability in NSW.

A certificate-based scheme where retailers must procure capacity certificates needs to be paired with a requirement that generators must sell them. There are a range of ways capacity certificate liquidity could be ensured, such as an obligation comparable to the existing MLO, a requirement for all certificates to be centrally cleared or a requirement on generators to sell a minimum volume into the market. As with the existing contract market, liquidity is crucial to efficient pricing and allowing retailers to meet their obligations. Shell Energy believes that it would be a problematic design if retailers were unable to comply because generators were unwilling to sell certificates that could have been sold.

There is also the question of the timeframe in which capacity certificates should be available. This decision relates strongly to the volumes of capacity certificates that generators can make available. Capacity certificates covering a full year could reduce the administrative burden, but, depending on what triggers compliance – e.g. exceeding P50 demand, use of RERT, actual LOR2 or LOR3 declaration – generators may be unwilling to sell a sufficient volume of capacity certificates due to the impacts of planned and unplanned outages over the year as well as summer derating of capacity. While demand generally peaks in summer in the mainland regions, there is not a large difference between winter peak and summer peak demand levels in some states, so the risk of wholesale reliability trigger events in winter or other seasons (after taking into account the impact of planned outages) remain. The electrification of some services typically provided by gas, e.g. heating and hot water in Victoria, could also shift the market to winter peaking. A quarterly or monthly approach would therefore provide more granularity to account for outages and allow generators to manage their own outage plans without the need for a market operators outage approval process but may require more regular checks on compliance.

Depending on the structure of this model, Shell Energy believes that a balancing market could be a worthwhile addition to allow generators and retailers to true up their certificate positions following an event. This would allow retailers to secure sufficient certificates to meet their obligation, and to allow generators who may have oversold certificates to procure replacement certificates, or indeed had higher dispatch/availability than originally forecast to sell more certificates. Alternatively, the cost impacts of being short of capacity certificates or having sold too many could be allocated on a 'causer pays' basis against any RERT dispatch.

A balancing mechanism allows for participants to ensure they remain compliant. Penalties should be a last resort for those failing to act in good faith. Retailers who may have under-procured by a trivial amount should not risk large penalties like the current RRO for failing to precisely estimate their demand ahead of time.

A certificate-based scheme would provide the same kind of incentive that the existing market price cap does for new investment or maintenance of current resources. To leave the market price cap at the current level of $15,000/MWh while also allowing generators to sell their capacity would therefore create a double capacity revenue payment. If this capacity certificate scheme is adopted, the AEMC Reliability Panel must be tasked with reviewing the reliability settings to factor in the use of capacity certificates in valuing the capacity provided by generators.

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Finally, we consider that there is merit in adopting a safety net at least in the early years of this model. This could take the form of a price cap to avoid high costs for little benefit to consumers. A price cap protects against extreme price outcomes and limits the incentive for parties to artificially create scarcity by not selling, or over-procuring certificates.

2 Essential system services

Shell Energy welcomes the ESB's proposed approaches to dealing with the increasing need for system services given the energy transition underway. We are encouraged by the ESB's preference for market-based approaches for services, such as the longer-term aim for a spot market for inertia and fast frequency response. The AEMC's draft determination on the fast frequency response rule change provided a strong explanation of the advantages of market-based approaches. The Commission noted:

> *"Where arrangements can function competitively through a market, they are more likely to support the economic dispatch of power system resources and help to reduce the long-term costs of power system operation in the long term interests of electricity consumers."*[15]

The Commission added:

> *"Spot market based provision of essential system services is preferred, where practicable, given it allows for full co-optimisation between services and energy, resulting in more efficient dispatch and pricing of services..."*[16]

Where possible, Shell Energy encourages the ESB to pursue market-based approaches for system services. We note that the AEMC is driving work on many of the essential system services reforms through rule changes such as fast frequency response, operating reserves, system strength and primary frequency response incentive mechanisms. We consider that the AEMC's work is largely the right process for consideration of these rule changes given the complexity and technical nature of them. Shell Energy has made submissions to the AEMC on several of these rule changes and will continue to do so as draft determinations and other papers are released for comment.

Shell Energy remains unconvinced of the need for an operating reserve in the NEM. It is entirely unclear how this would change generator behaviour beyond what the existing market settings already do. The presentation on modelling on an operating reserve that was presented to the ESB's Technical Working Group appears to demonstrate this as well, with little seeming benefit provided by an operating reserve for the scenarios modelled.

As with all the system services rule changes, it will be crucial to determine whether the benefits will outweigh the costs. While the AEMC appears to be taking this approach, we do have some concerns around the estimation of both costs and benefits for recent rule changes. In Shell Energy's view, we have observed some worthwhile measures rejected on the grounds of questionable estimates of implementation costs, such as extending the reliability assessment outlook in MTPASA to three years. Further, other rule changes have had large system-wide costs dismissed due to unproven and often unquantified benefits (e.g. Five Minute Settlement).

Consumers are understandably wary of extra costs incurred, particularly through less obvious mechanisms than the wholesale market. Shell Energy recommends that the ESB assert the importance of determining clear and convincing measures of benefits and costs in order to appropriately assess system security reforms.

Shell Energy has previously provided comments on the development of the Unit Commitment for Security (UCS) mechanism. We do consider that the UCS model could provide benefits in the form of a more transparent approach to the existing directions process. However, the key to this outcome will be to ensure that over-procurement of services does not happen, and new rules must require AEMO develop a transparent methodology to determine the volume of procurement required. We also note the interaction between the UCS and the AEMC's efficient management of system strength on the power system rule change.[17] The draft rule change puts the responsibility on transmission network service providers (TNSPs) in conjunction with AEMO to

[15] AEMC, *Fast Frequency Response Market Ancillary Service rule change draft determination*, April 2021, pp 23
[16] AEMC, *Fast Frequency Response Market Ancillary Service rule change draft determination*, April 2021, pp iii
[17] AEMC, *Efficient management of system strength on the power system, Draft rule determination*, 29 April 2021

procure system strength when and where it is required. In that context it makes a degree of sense for AEMO to dispatch any system strength contracts procured by TNSPs via the UCS process.

What is less clear to Shell Energy is the need for the UCS alongside the proposed System Security Mechanism (SSM) which is designed to procure for services over the short-term where there is no market for the service. The SSM and UCS appear to be attempting to achieve the same aims, so it appears to be duplicative to use both mechanisms. Shell Energy sees that the shorter-term SSM would make more sense as it would allow AEMO to dispatch system strength contracts as needed when there is a need for such a service. This should reduce the risk of over-procurement of UCS and the use of system strength contracts influence spot price outcomes in the energy market.

While the concept of bringing more rigour to the provision of system strength is a positive move, it fails to address one of the key drivers behind the need for AEMO to issue directions, which is due to a flaw in the National Electricity Rules (NER).[18] Currently, if a generator is constrained on it will not necessarily recover the costs associated with continuing to generate, including start-up cost (if required) and operating at its minimum load. Consequently, generators will bid unavailable in order that AEMO would need to issue them a direction. Once they have been issued a direction to generate, then they can recover the full costs of doing so. Simple changes to the NER similar to that introduced to the compensation provisions during periods of market suspension,[19] or the compensation provisions during an administered pricing period,[20] could resolve this unfortunate distortion without the need to shift towards the UCS or SSM.

This simple change would allow generators providing system services to continue to dispatch as and when required while being certain their costs of production can be recovered. We recommend that the ESB consider these changes to the NER that could allow generators to recover costs if constrained on by AEMO before proceeding with the introduction of what will invariably be more complex changes to the NEM and increase overall market costs. In considering this change we ask that the ESB also consider the type of cost recovery mechanism to be used. We recommend this should be introduced on a beneficiary pays basis rather than simply be imposed on market customers, since generators also benefit from the provision of power system services.

[18] Clause 3.9.7(d)
[19] Clause 3.14.5A
[20] Clause 3.14.6

3 DER and demand-side

With increasing levels of solar PV, the progressive growth of battery storage, the potential for electric vehicles to play a major role in demand and supply plus the advancements in digital technologies, the NEM will need to adjust to these changes in technology. There is also scope for increased levels of participation in the market from consumers who choose to do so. The Paper outlines a series of issues that could be addressed to harness the potential of distributed energy resources (DER).

There are quite a number of subjects that this workstream is seeking to address including minimum demand, tariff reform, and DER visibility. Some of these will need extensive individual work to best determine a pathway forward for any new requirements, rules or policies. Others, such as tariff reform, could be implemented reasonably quickly. In the case of tariff reform, we have noted that there has been a historical reluctance from governments to implement these necessary changes.[21] Shell Energy considers that there is scope to deliver broad market, system and consumer benefits from tariff reform and widespread cost-reflective pricing. We understand the concerns around vulnerable customers and contend that targeted support is the best way of address inequities.

3.1 Scheduled-lite arrangements

With increasing volumes of behind-the-meter solar PV and battery storage in the NEM, along with the potential for electric vehicles to become a major source of both load and supply, Shell Energy can see real value from more information on these types of resources being made available to the market operator. This could improve both demand forecasting and dispatch outcomes in the NEM.

To enable this, the ESB has set out two potential models to allow demand-side resources to signal their intentions in the NEM. Shell Energy considers the visibility and dispatchability designs detailed in the Options Paper to be reasonable and appropriate measures to increase the provision of demand-side information in the NEM. It is clear that a significant amount of work is still required to determine exactly how these models would operate in the market.

We see that the visibility model provides a signal to operators of DER that their expected output is an important input for the efficient operation of the market. The total region-level data (both in terms of participant forecasts and actual output) would also be a valuable source of information the wider market. As the volume of DER grows, we expect that this information will become more crucial to allow for the smooth functioning of the market and to deal with issues including minimum demand.

The dispatchability model bears significant similarities with the Wholesale Demand Response Mechanism (WDRM) and the Demand Side Participation Information Portal (DSPIP). It is therefore somewhat unclear as to what point of difference this model would provide given the possible incentives described, e.g. reduced RERT and FCAS causer pays costs. Shell Energy sees that load which seeks to be dispatchable would likely seek to participate in the WDRM, while load that is either ineligible for the WDRM or unwilling to participate could already be captured in the DSPIP. That is not to say that further exploration of a dispatchable model is unwarranted. We do see that there would likely be broader benefits in seeing DER participate in the market as an active participant. Finding the right ways to incentivise this is key. Again, there may be a case for this to be required of certain participants, in particular where large, aggregated volumes of storage may be seeking to charge or discharge in response to spot market prices.

Shell Energy will continue to engage with the ESB and other organisations such as the AEMC as they seek to develop these options further.

[21] For example, the Victorian Government's 2017 Advanced Metering Infrastructure Tariff Order allows customers to opt-out of cost-reflective tariffs that distribution network service providers have assigned. There is no indication that the Victorian Government will change this.

3.2 Flexible Trading Arrangements

Shell Energy is troubled by the seeming re-emergence of the multiple trading relationships (MTR) rule change that the AEMC rejected in 2016, in the options paper. While the ESB states it "is not considering the previously proposed Multiple Trading Relationship (MTR) changes at this stage", the flexible trading model described are very much akin to the previously rejected MTR rule change.

MTR as an option may benefit some very select consumers, and they can access it now via using two connection points. However, changing the entire market and imposing huge implementation costs to benefit very few customers would be a poor outcome for the overwhelming majority of customers.

We understand the notion that individual consumers may derive benefits from being able to procure services from multiple electricity providers (not necessarily retailers) at a single connection point. The ESB points to technologies such as EVs, pool pumps, air conditioners and hot water systems as appliances whose consumption could be controlled by a third party as opposed to the consumer's existing energy retailer. The ESB also points to wanting to enable new business models to emerge as a reason to allow for unbundling of services.

In practice, the notion of unbundling services from bulk energy supply is unlikely to deliver benefits on a system-wide basis. Stripping out parts of a customer's energy consumption in order for a service provider to manage just a portion of a customer's load makes little sense. If a retailer is unable to make an offer that is sufficiently competitive with the incumbent offer for the entire load, it is unclear how reducing the volume would allow it to offer a more competitive offer. This would be contrary to the basic economies of scale on which retail businesses are built.

While we understand that a proportion of customers do choose to pay more to access environmental, convenience or quality benefits, cost is generally the deciding factor for electricity decision-making. This cost is not only about potential bill savings, but also about the capital cost to the customer on entering the arrangement. For example, solar PV installations have increased significantly as costs have come down and the time it takes to pay back the capital cost has reduced. Similarly, we expect that only a very small number of consumers would opt for flexible trading arrangements products and services unless they can be demonstrated to lead to lower energy bills, such that the bill savings pay back the initial capital investment over a reasonable time period.

In order for flexible trading arrangement products and services to lead to lower energy bills, they must either allow the customer to purchase energy at a lower rate (or sell energy at a higher rate), or to purchase less energy (or sell more energy), compared to if they were to contract just one retailer. As described above, it is not expected that economies of scale would allow a retailer to offer a more competitive rate for servicing just part of a customer's load. Flexible trading arrangements could have the ability to reduce the volume of energy purchased or increase the energy sold by a customer, through providing a means of generation, storage, or load management. However, these products or services would have the same impact on consumption or generation as equivalent products offered by a retailer that services the customer's entire load.

Even if the impact to energy bills was neutral, it is expected that the upfront capital costs of entering a flexible trading arrangement would outweigh the environmental, convenience or service quality benefits for most customers. We therefore do not believe that the value proposition is sufficiently strong to drive material customer demand for flexible trading arrangements.

Further, the ESB suggests the possibility of retail tariff arbitrage as one potential advantage of the flexible trading arrangements model presented, simply shifting load from one retailer to another. Given that retailers must comply with the RRO based on their retail load, this presents an extraordinary set of risks. One retailer could simply direct their customers to use load from the other retailer during the 'gap period', essentially passing on all the risk to another party, while delivering nothing additional in terms of reliability. This is precisely the reason that under the opt-in arrangements for the RRO, sites with multiple connection points would have to opt-in for all connection points. This was to prevent the possibility of a user opting in for one connection point but shifting their load during a gap period to a second connection point to pass on the compliance requirements to another party.

We recognise that the Wholesale Demand Response Mechanism (WDRM), is in essence a form of flexible trading arrangement, with a third party – the Demand Response Service Provider (DRSP) – providing a service to the customer separate to the customer's retailer. Shell Energy sees that the WDRM provides a bespoke service for customers who wish to provide demand response separate to their retailer. While there will be a single baseline at this stage and participation may be limited we expect this to grow over time as AEMO deploys more baseline methodologies and baselines improve in accuracy. Crucially, the WDRM also ensures the retailer is made 'whole' through the reimbursement rate, which provides an imperfect but acceptable level of compensation for the hedging costs that are still incurred. If the ESB considers that there could be more demand response participating in the market then it would be preferable to leverage the existing WDRM and propose new baseline methodologies than seeking to establish complex new flexible trading arrangements.

3.3 Other DER issues

Shell Energy agrees with the proposed principles for DER interoperability. We consider that ensuring interoperability of devices will be an important step towards enabling customers to both access devices and services through different providers. Locking consumers to specific providers would be a poor outcome and limit the benefits that both consumers and the market could deliver.

The ESB queries whether constraints on switching are likely to occur though the development and introduction of international standards such as IEEE 2030.5. Our understanding is that IEEE 2030.5 would provide just a partial solution and may indeed lead to some limitations or challenges in switching that others would not. We believe that IEEE 1547 would provide a more fit-for-purpose solution that would deal to risks around customer switching in that it captures a wider set of protocols than IEEE 2030.5.

4 Transmission and access

Shell Energy is concerned that:

- "in the long term, the ESB's preferred solution for access reform is to shift to locational marginal pricing and financial transmission rights"[22]
- the ESB is recommending medium-term, system wide reform "designed to be a stepping-stone towards a longer-term solution [of] locational marginal pricing and financial transmission rights"[23].

An access regime based on locational marginal pricing (LMP) and financial transmission rights (FTR) has been repeatedly and comprehensively rejected by industry and consumer stakeholders. Consistent with this opposition, we consider that progressing medium-term reforms designed to move towards an LMP/FTR regime to be a mistake. We believe that a prudent path forward would be to:

1. cease all work on the medium-term, whole-of system reforms designed as a 'stepping-stone' to a long-term LMP/FTR regime
2. over the medium term, engage meaningfully with stakeholders to develop a workable alternative long-term access regime that does not require LMP/FTR
3. in the near term, focus on developing renewable energy zone (REZ) access frameworks.

Section 4 outlines our rationale for this position.

4.1 Defining the problem

A core challenge throughout the recent AEMC/ESB attempts to reform transmission access has been agreeing on the problem the reforms should aim to address. Stakeholders have observed that an LMP/FTR regime appears to be a "solution looking for a problem"[24], because the problem statement has changed over time, but the proposed solution is invariably a version of LMP/FTR.

Section 4.1:

- summarises the criteria the ESB has applied to the Paper's mooted system-wide access reforms
- outlines Shell Energy's view on what any new transmission access framework should try to achieve
- compares the ESB's priorities with those of Shell Energy.

We use this analysis as the basis for our comments on the Paper's access reform options.

4.1.1 The ESB's criteria to assess potential access regime options

Figure 1 below summarises the four problems the ESB is aiming to solve with whole-of-system transmission access reform. They form the basis for the criteria the ESB uses throughout the Paper. I.e. for each access regime option, the ESB assesses the extent to which it would address these issues.

[22] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 89

[23] ibid, pp 83

[24] See previous submissions to COGATI, REZ and Post-2025 consultation processes including: Neoen, *Re Coordinating Generation and Transmission Investment*, 19 October 2020, pp 1. Accessed from: www.aemc.gov.au/sites/default/files/2020-10/EPR0073%20-%20Neoen%20submission%20COGATI% 20interim%20report%2019Oct2020.pdf; Infigen, *ESB REZ Consultation*, 12 February 2021, pp 2-3. Accessed from: energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/Infigen%20Response%20to%20Consultation%20Paper%20on%20interim%20REZ%20Framework%20.pdf;

Figure 1: ESB criteria for transmission access regimes[25]

PROBLEM STATEMENT

Locational signals in investment timeframes	Congestion management in operational timeframes	Efficient signals for storage	Inability to hedge risk
• Current market design rewards generators and storage for locating in the wrong place.	• Generators and storage do not operate or use the network efficiently – due to congestion, and the fact that they all receive the same regional price.	• Storage is able to be flexibly located and it can either relieve or worsen congestion, depending on how it is used. • Framework should reward storage for contributing to efficient overall outcomes.	• Market participants have limited tools to manage risks of congestion, falling marginal loss factors and technical issues due to others' locational decisions

We offer several observations on these criteria.

- As an overarching comment, none of the criteria explicitly address what we consider to be the primary issue: coordinating efficient new-build generation and transmission. This is discussed further in Section 4.1.2.
- The Paper's rationale for the first criterion appears to discount the fact that, under the current market design, volume risk penalises generators and storage for locating in congested areas.
- The Paper doesn't explicitly state whether the ESB weights some criteria more heavily than others. However, based on the focus of the Paper and associated briefing, it appears as though the ESB prioritises the second criterion, "congestion management in operational timeframes" most highly. Further, it appears as though the ESB is most focussed on creating operational-timeframe price signals, rather than considering all options that would physically reduce congestion. In our view, the criterion should be focussed on addressing the physical challenge (congestion) rather than the ESB's preferred method to address the challenge (operational-timeframe price signals).
- The ESB's intent for the third criterion appears to be primarily to encourage storage to locate behind network constraints so as to reduce the amount of spilled energy during times of congestion. However, this role could be performed by any dispatchable load, not just from storage charging. Further, given that storage generates revenue from discharging, if congestion occurred at times of high prices at the RRN, then the storage would not be able to benefit from them if it was located behind the constraint. Therefore, there may be instances where an efficient signal for storage would result in it locating in front of the constraint. This would be the case regardless of whether there was LMP. A more appropriate criterion to satisfy the ESB's intent may be 'efficient signals for storage and other dispatchable load'.
- The intent of the fourth criterion – to "manage risks... due to others' locational decisions" – is sensible. However, the use of the term 'hedge' in the title, "inability to hedge risk", seems to indicate an inherent bias for financial products (e.g. FTR) as the best way to manage risk. This is inappropriate, as there may be more effective ways to manage risk. For example, risk could be managed through choice of location at the time of investment decision if the access regime gave proponents certainty relating to their level of firm physical access.

[25] ESB, *Post 2025 Market Design Program, Options Paper Briefing, Transmission and Access*, 7 May 2021, pp 19

4.1.2 Shell Energy's proposed objectives

If the transmission access regime is to change from the status quo, Shell Energy believes the primary objective of the new regime should be to facilitate efficient, coordinated investment in generation and transmission infrastructure. This can be broken down into several principles.

1. The transmission access framework should provide efficient locational signals for new generation investment. These signals should be clear prior to the investment decision and facilitate optimising between transmission costs and other considerations (e.g. generator input resource strength).
2. The transmission access framework should provide connecting (and existing) generators with a reasonable level of certainty in order to support investment decisions. Primarily, this means:
    - discouraging any new generators from materially harming the access of generators that are already connected
    - preventing the construction of new network infrastructure that would materially harm the access of generators that are already connected.
3. The transmission access framework should not prevent new generators from connecting, providing they do not cause material harm to the access of existing generators (as per principle 2). I.e. new connecting generators should be enabled to connect anywhere in the network as long as they take action (e.g. paying to augment physical infrastructure, operating their plant within certain constraints) to prevent their connection from causing material harm to the access of existing generators
4. The transmission access framework should facilitate private sector investment in transmission assets. In addition to the 'do no material harm' concept in principle 2, this requires investors to be protected from new connectees 'free-riding'.

As well as facilitating efficient infrastructure investment, the transmission access framework should also abide by core principles that underpin the National Electricity Market (NEM).

5. The transmission access framework should not undermine the effective operation of financial markets.
6. The transmission access framework should facilitate an efficient and equitable apportioning of risks and costs between parties that benefit from new network investment. This is distinct from the current system, whereby consumers bear all the costs and risks of regulated transmission infrastructure.

4.1.3 Comparison of ESB and Shell Energy objectives for transmission access reform

Similarities

Shell Energy's principles 1-4 (see Section 4.1.1) are an expansion of the ESB's first criterion, 'locational signals in investment timeframes'. In our view, this should be given more weighting than the other criteria, because appropriate locational signals in investment timeframes would mitigate the challenges the ESB's other criteria aim to address.

Principles 1-4 also address the intent of the ESB's fourth criterion. This is because an access regime that complied with these four principles would allow proponents to identify and price risk during the investment phase. As a result, participants would not need additional tools to manage access risk.

A framework that complied with principles 1-4 would also reduce the likelihood and extent of congestion (in operational timeframes), without the need to provide price signals in operational timeframes (relevant to the ESB's second criterion).

Additional Shell Energy principles

Shell Energy's principles 5-6 are additional to the main criteria applied by the ESB.

Principle 5 is to prevent an access regime that has the unintended consequence of undermining the smooth operation of electricity financial markets. In Shell Energy's view, this would likely have a net-negative impact, even if the access regime appeared to address other issues (e.g. real-time congestion management). We discuss how an LMP/FTR regime would negatively impact financial markets in Section 4.2.

On principle 6, the Paper notes that "the ESB has [already] provided advice to Energy Ministers on transmission cost allocation"[26]. This seems to imply that the ESB is treating fair and equitable cost allocation as a secondary consideration for access design. Given the National Electricity Objective (NEO) is to deliver outcomes in the long-term interests of electricity consumers, we believe that cost and risk allocation should be explicitly considered as part of assessing transmission reform options.

Congestion management in operational timeframes

As noted in Section 4.1.1, it appears as though the ESB gives the highest priority to creating a price signal that reflects congestion in operational timeframes. The ESB typically uses the example of disorderly bidding to demonstrate why this is a problem that needs to be solved.

In previous submissions to the ESB and AEMC, stakeholders including Shell Energy[27] have outlined that:

- disorderly bidding is not a material problem
- there is no compelling evidence that disorderly bidding will become a material problem in the future
- introducing LMP/FTR would not solve disorderly bidding (see Section 4.3.1 for an example).

It follows that addressing disorderly bidding should not be a primary objective of a transmission access framework. Further, if investment in generation and transmission was appropriately coordinated, then inefficiently high levels of congestion would not be a material issue; therefore, there would be even less incentives for, or chance of disorderly bidding becoming a material problem in the future. Additionally, the economic inefficiencies from disorderly bidding will reduce as the proportion of zero-marginal-cost generators increases. Shell Energy disputes the NERA modelling referenced in Part B of the Paper, which overestimates the costs of disorderly bidding, and underestimates the risks and costs of LMP/FTR[28].

Shell Energy acknowledges that the ESB remains unconvinced by these arguments. As a result, we explicitly address congestion management in operational timeframes throughout the rest of this submission. However, we focus on each option's ability to address the physical challenge (congestion) rather than whether the option delivers price signals in operational timeframes. We urge the ESB to reconsider its apparent view that:

- real-time locational pricing is the only (or best) way to manage congestion.
- real-time price signals for congestion management are as important as (or more important than): facilitating the coordination of efficient generation and transmission investment (the ESB's first criterion) and managing investment risk due to the location of new-entrant generators (the ESB's fourth criterion)

Efficient signals for storage and other dispatchable load

As discussed in Section 4.1.1, Shell Energy agrees that storage and other dispatchable load should be incentivised to locate in parts of the network that deliver the greatest whole-of-system benefits (which may

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[26] ESB, *Post 2025 Market Design Program, Options Paper Briefing, Transmission and Access*, 7 May 2021, pp 79

[27] ERM Power, *RE: Coordination of Generation and Transmission Investment Proposed Access Model – Discussion Paper*, 8 November 2019. Accessed from: www.aemc.gov.au/sites/default/files/2019-11/ERM%20Power%20-%20Proposed%20access%20model.pdf

[28] ERM Power, *RE: Transmission access reform: Updated technical specifications and cost-benefit analysis, 7 September 2020*, 19 October 2020. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/epr0073_-_erm_power_submission_cogati_interim_report_19oct2020.pdf

include additional benefits above simply storing surplus generation). However, it is not clear that broad transmission access reforms are the only (or best) way to achieve this goal. For example:

- The market rules could be changed to allow storage to charge (or other dispatchable load to operate) for free when/where the additional load would alleviate congestion that would otherwise result in zero-marginal-cost variable renewable energy (VRE) being curtailed. The ESB has previously proposed something similar as part of its Stage 2 REZ consultation[29].
- Alternatively, the NER could be tweaked to allow a market-based solution. For instance, the NER could stipulate that generators who choose to locate in a congested area could be subject to "first off" provisions when network congestion occurs. This would provide an economic signal to either supply their own storage resource, or contract with another party to provide this service on commercial terms.

In summary, a new transmission access framework should not be discounted on the basis that it does not provide more locational signals than the status quo to incentivise storage to reduce VRE spillage. Trying to meet too many objectives with a new access framework has the potential to result in a suboptimal outcome.

4.2 Recap of negative LMP/FTR impacts

In previous submissions to the AEMC and the ESB, Shell Energy and other stakeholders have detailed the varied and substantial negative impacts of an LMP/FTR access regime. Given that the ESB has not explained how these issues could be addressed, we are concerned that "in the long term, the ESB's preferred solution for access reform is to shift to [LMP] and [FTR]"[30].

Before assessing the ESB's mooted medium-term access options (which are a stepping-stone to LMP/FTR) in Section 4.3, we consider it important to first reiterate key drawbacks of an LMP/FTR regime. This is the focus of Section 4.2. The drawbacks we have highlighted are inherent to an LMP/FTR regime – they would not be resolved even with a long transitional period.

For the sake of brevity, we only summarise a subset of drawbacks. For more comprehensive feedback, we urge the ESB to review previous advice from Shell Energy and other stakeholders[31]. To be clear, we consider that the drawbacks of an FTR/LMP regime would vastly outweigh any positive impacts from potential improvements in dispatch efficiency.

4.2.1 Selected negative impact on financial markets

As outlined in Section 4.1.2 (see principle 5), Shell Energy believes that the transmission framework should not undermine the effective operation of financial markets. Our rationale is that financial markets are fundamentally necessary to facilitate investment and manage risk. Without functioning financial markets, consumers would suffer from higher prices and potentially lower reliability (and/or government intervention that would further increase cost).

Unfortunately, an LMP/FTR regime would have unavoidable negative impacts on the NEM's financial markets.

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[29] ESB, *Renewable Energy Zones, Consultation paper*, January 2021, pp 41. Accessed from: https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20Interim%20REZ%20framework%20Stage%202%20consultation%20paper_0.pdf

[30] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 89

[31] Submissions to various consultation processes including the Stage 2REZ consultation and COGATI. Of particular note is: ERM Power, *RE: Transmission access reform: Updated technical specifications and cost-benefit analysis, 7 September 2020*, 19 October 2020. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/epr0073_-_erm_power_submission_cogati_interim_report_19oct2020.pdf

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Materially reduced liquidity

In the NEM today, liquidity for regional reference node (RRN)-based contracts is facilitated by the aggregation of the region's generation. Basing contracts on the regional reference price (RRP) creates a common product, which allows market participants to flexibly manage a range of risks, including congestion.

The core concept of LMP is to split up the NEM's regions into a large number of nodes. In the LMP/FTR model proposed by the AEMC, generators and scheduled load would be settled at their respective LMP, and non-scheduled load would be settled at the RRP (the load-weighted average price). We believe settlement of generators at their respective LMP would materially reduce the liquidity of common, like-for-like contract products because generators would seek to contract only at their respective nodes. This would have negative impacts for over-the-counter (OTC) and exchange-traded contracts, and retailers would have less options to manage their contracting and credit risk through secondary market trades. This is because retailers would no longer be able to purchase comparable (common) products from the direct market to trade with secondary markets. As the trading products would be no longer comparable, the common pool of contract availability would be reduced. This reduces liquidity for the retailer.

Another reason FTR would reduce liquidity is that the pool of firm FTR made available to market is likely to be made on a conservative estimate of transmission network capacity (e.g. 80% of underlying capacity) to allow for outages. This would limit the amount of FTR available to back hedging contracts, and hence maintain current levels of liquidity.

In addition to increasing hedging costs (which would be passed through to consumers), reducing liquidity would impact competition by disadvantaging non-vertically integrated retailers. The negative impacts of reduced liquidity would be magnified for nodes without substantial firming generation and/or with a weak connection to the rest of the grid.

Additional risks and their allocation

LMP would introduce congestion price risk for generators, which is additional to the congestion volume risk they already manage.

The intent of an FTR is to function as a risk management tool to manage generator exposure to volume and price risk (discussed henceforth as 'congestion risk'). However, in our international experience, we have observed that generators demonstrate little appetite to manage their additional congestion risk via purchasing FTR. If FTR were implemented in the NEM, we expect risk-averse generators would manage their congestion risk by selling energy at the generator connection point (the local node) rather than the RRN. This would shift congestion risk to the energy buyer, who would incur the cost of the related FTR.

As a result, we believe retailers seeking to purchase energy (to manage both market and regulatory risk) would become the dominant buyers of FTR. To be clear, retailers would be required to manage both the pricing risks associated with buying contracts from different suppliers at different nodes, and the procurement of FTR from these various nodes to the central RRN. This additional complexity and risk to the retailer would increase cost to customers. The increased cost would likely be higher in the NEM (compared to other jurisdictions with LMP/FTR), due to the NEM's high market price cap.

If generators did purchase FTR, we expect their willingness to offer contracts at the RRN would still deteriorate (see above for more discussion of reduced liquidity and how this increases risks for retailers), as contracting FTR for their nameplate capacity would be prohibitively expensive. This adjustment would flow through in both bidding and unit commitment strategy, with lower-hedged generators focussed on reducing both fixed and variable operating costs, and maximising returns from the spot market.

The impact on the financial markets following the introduction of LMP/FTR could also have a significant negative impact on liable entities' compliance with the RRO, even if changes are made to the current RRO framework. As discussed above, generator contracting decisions would likely change under the proposed LMP/FTR framework. Consequently, liable entities' ability to source qualifying contracts or capacity certificates would be compromised, resulting in higher costs for contracts or capacity certificates (which would ultimately be passed through to consumers). It needs to be noted that with regards to the RRO, liable entities must contract, but generators have the choice not to do so.

4.2.2 Selected negative impacts on investment and consumer prices

As outlined in Section 4.1.2, Shell Energy believes that, if the transmission access regime is to change from the status quo, the primary objective of the new regime should be to facilitate efficient and coordinated investment in generation and transmission infrastructure. However, there is no evidence to suggest that an LMP/FTR regime would drive coordinated transmission investment; and such a regime would actually have a negative impact on generation investment. By damaging the investment environment required to support the industry's transition, LMP/FTR would increase the cost to consumers and/or governments aiming to encourage investment. Damaging the investment environment would also have negative impacts on resource adequacy. This runs counter to the intent of the RRO (including the currently proposed changes). We consider that designing a resource adequacy scheme (RRO-based, or otherwise) to counteract the negative investment impacts of LMP/FTR would be non-trivial, and would likely come at a high cost to consumers.

<u>FTR would increase generation investment uncertainty and the cost of financing</u>

In general, new generation will only enter the market when an investor expects the average price they will receive is above their long-run average cost. This allows recovery of operating and investment costs, plus a return. Assuming a progressive FTR auction process (as previously proposed by the AEMC), an LMP/FTR regime would saddle investors with the unknown costs of FTR, and an inability to source sufficient FTR volumes prior to making an investment decision. This would be exacerbated by:

- the likely situation where FTR contracts are shorter than the life of the generator
- the conservatively small FTR pool to account for network outages (discussed in Section 4.2.1).

The end result to investors would be increased uncertainty and therefore risk. This would likely lead to higher financing costs. In order to recoup these costs, the investors would need to charge more, which would ultimately drive up prices for consumers.

<u>Dynamic loss factors would lead to loss volatility, further adding to uncertainty</u>

Currently, a precalculated annual transmission loss factor is applied to generators and loads in the NEM. This provides certainty for market participants regarding contracting volumes for risk management purposes.

Under the COGATI LMP/FTR proposal, loss factors would be dynamic. However, dynamic loss factors are inherently volatile – typically up to ±15-20% (as currently calculated by AEMO) from the average yearly calculated static losses at the local node level. Dynamic loss factor volatility increases at times of higher variance in system demand, and is generally higher during periods of higher demand and prices (when higher network loading conditions are experienced).

As a result of this volatility in dynamic losses, we expect that generator contracting would be further[32] reduced, thereby causing further harm to contract market liquidity. This would coincide with an expectation that retailers will need to hedge additional volumes to cover the associated dynamic loss increase on loads. At times of medium-to-low system demand and lower prices, retailers may find themselves over-

[32] In addition to the aforementioned reduction associated with introducing LMP/FTR

hedged – the additional costs of which would then flow through to consumers. Dynamic loss factors would also further reduce liable entities' ability to comply with their RRO obligations.

4.3 Analysis of the ESB's mooted medium-term access reform options

Section 4.3 critiques the ESB's analysis of the medium-term access reform options outlined in the Paper. We do this with reference to the ESB criteria and Shell Energy principles discussed in Section 4.1. We arrive at different conclusions to the ESB, whose views are summarised in the traffic light assessment in Figure 2 below.

As an overarching observation, we note that the Paper has dedicated approximately four times as much page space to the congestion management model (CMM) compared with each mooted alternative (a locational connection fee, and generator transmission use of system charges (GTUOS)). The Paper subsequently asserts that some variation of the CMM is the best option. This could indicate a potentially flawed approach to the ESB's assessment; i.e. by considering alternative options in less detail, the ESB may have missed how their respective designs could be improved to deliver better outcomes. Indeed, as outlined throughout Section 4.3, we have assessed the CMM to be less favourable than the ESB has indicated, with the alternatives appearing more attractive if they are well designed.

Figure 2: The ESB's 'traffic light' assessment of its mooted access options[33]

	Option	Locational signals	Congestion management	Efficient signals for storage	Ability of generators to hedge risk
1	Congestion management model				
2	Congestion management model – REZ version				
3	Connection fee				
4	Generator TUOS				
5	Hybrid connection fee & congestion management model				

Our comments throughout Section 4.3 do not imply that we support whole-of-system, medium-term access reform. The opposite is true (summarised in Table 1 below and discussed in detail in Section 4.4). However, we are committed to engaging constructively, and hope that our feedback helps the ESB to understand why system-wide reforms based on LMP and FTR are not necessary.

Table 1: Analysis of ESB arguments for medium-term, whole-of-system access reform

ESB argument for medium-term reform	Shell Energy position
LMP/FTR is the long-term goal, so the system should gradually transition towards it.	An access regime based on FTR and LMP has been repeatedly and comprehensively rejected by industry and consumer stakeholders due to a range of negative impacts (see Section 4.2). It does not make sense to actively progress towards an outcome that has not been agreed. Progressing towards LMP/FTR creates regulatory risk, which

[33] ESB, *Post 2025 Market Design Program, Options Paper Briefing, Transmission and Access*, 7 May 2021, pp 27

ESB argument for medium-term reform	Shell Energy position
	negatively impacts investment decisions. Implementing substantial medium-term reform would come at a cost.
Whole-of-system reforms are necessary for REZs to work well.	As outlined in our submission[34] to the ESB's Stage 2 REZ consultation, we consider that a well-designed, well-implemented REZ framework accompanied by appropriate planning processes would address the major issues relating to transmission and access in the medium term. Key REZ design elements can mitigate the risk to REZ participants of others' locational decisions. For example, all network infrastructure (even if geographically distant from the colloquially understood REZ area) constructed or upgraded to facilitate the connection of a REZ should be included when defining the boundary of REZ access rights. In the case of NSW, this has been provided for in 19(2) of the *Electricity Infrastructure Investment Act 2020* (the EII Act).
The shortcomings of the existing access regime should be addressed as soon as possible.	The ESB's view lends a false sense of urgency to whole-of-system reforms. We consider that REZs should be the focus in the short-to-medium term, in conjunction with broader consideration around what a long-term access regime should look like. See Section 4.4 for our proposed pathway for future work.

4.3.1 The congestion management model

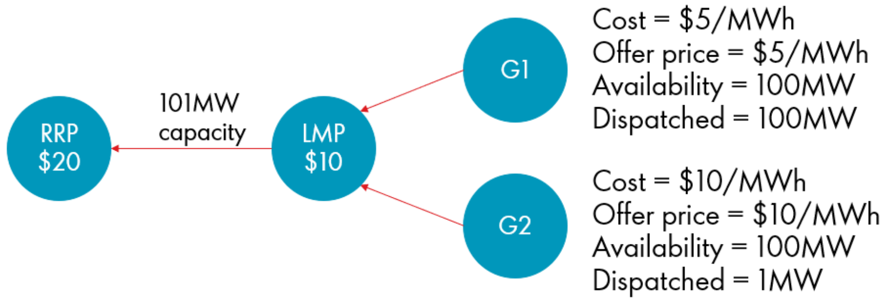
Locational signals for investment

Shell Energy agrees that the CMM does not provide locational signals to facilitate efficient, coordinated investment in generation and transmission infrastructure. The CMM may in fact discourage investment, as it is a step closer to a full LMP/FTR regime, which increases risks for investors (see Section 4.2).

Congestion management in operational timeframes

The ESB's main argument for the CMM is that it would remove incentives for disorderly bidding[35]. However, in reality it would only serve to incentivise a different type of disorderly bidding. To understand how, consider the example shown in Figure 3, designed to closely resemble the stylised example commonly used by the ESB[36].

Figure 3: CMM if generators behaved as the ESB intended



[34] ERM Power, *RE: Stage 2 REZ consultation*, 12 February 2021, pp 3-4. Accessed from: https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/ERM%20Power%20response%20to%20consultation%20paper%20on%20interim%20REZ%20framework.pdf
[35] ESB, *Post 2025 Market Design Options – A paper for consolation, Part B*, 30 April 2021, pp 94-98
[36] ibid

If both G1 and G2 behaved as the ESB intended (i.e. bids were reflective of costs) under the CMM model, the financial outcomes would be as follows:

Profit = (RRP × dispatched quantity) – (RRP – LMP) × dispatched quantity + ["share of settlement residue that would otherwise have arisen"] – (cost × dispatched quantity)

G1 profit = (20 × 100) – (20 – 10) × 100 + [50% × 101 × (20 – 10)] – (5 × 100) = $1005.00

G2 profit = (20 × 1) – (20 – 10) × 1 + [50% × 101 × (20 – 10)] – (10 × 1) = $505.00

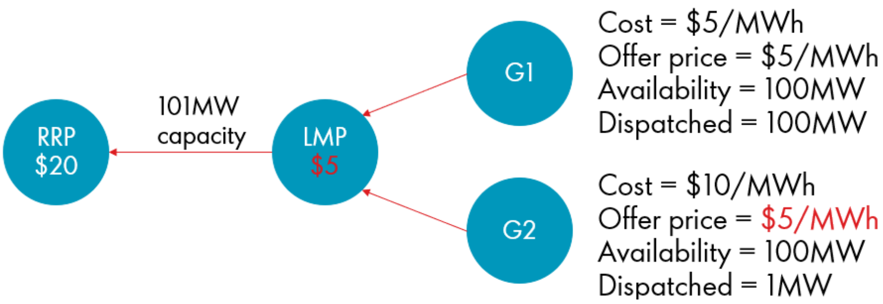
However, this is not profit-maximising behaviour for G2. Rather than bidding at its cost, the CMM would incentivise G2 to bid 1MW as close as possible to the offer price of G1, which would maximise the settlement residue component of G2's revenue (underlined in the equation below).

This strategy is highlighted in red in Figure 4 below, and would result in the following financial outcomes:

G1 profit = (20 × 100) – (20 – 5) × 100 + [50% × 101 × (20 – 5)] – (5 × 100) = $757.50

G2 profit = (20 × 1) – (20 – 5) × 1 + [50% × 101 × (20 – 5)] – (10 × 1) = $752.50

Figure 4: CMM if G2 behaved to maximise profit



We would be pleased to provide more detail on this example if it would assist the ESB's understanding.

As explained in Section 4.1.3, Shell Energy does not believe that disorderly bidding is a material issue, but we acknowledge that the ESB disagrees. The above example clearly indicates that CMM does not eliminate incentives for disorderly bidding. Therefore, it would not be effective in addressing the problem the ESB is trying to solve.

In addition to not solving the perceived problem of disorderly bidding, the CMM would not solve the physical problem of congestion – it would just put a price on it via the congestion charge, before largely removing the price signal via the congestion rebate. The best way to physically reduce congestion is to coordinate efficient investment in generation and transmission, which requires investors to have confidence that new-entrant connectees will not undermine their investments (see principle 2 in Section 4.1.2). The CMM does not do this.

Efficient signals for storage

As discussed in in Section 4.1.3, we consider that signals for storage could be addressed by mechanisms alternative to whole-of-system access reform, and should be a 'second-order' consideration. Nonetheless, we acknowledge that the ESB may not agree, so we provide the following comments. This caveat applies for all subsequent subsections in Section 4.3.

The example given in the Paper[37] is for a situation where congestion occurs at times of low prices, but is alleviated at times of high prices. For this specific scenario, it is true that the CMM as described may incentivise storage (or other scheduled load) behind the constraint to operate in a way that reduces spilled VRE.

However, as discussed in Section 4.1.1, there is a risk that congestion may occur at times of high prices. If this were the case, then a storage asset (and any collocated generators) would be negatively impacted by locating behind the constraint. Because the absolute value of the price floor (-$1000/MWh) is so much smaller than the price cap ($15000/MWh), we consider that there will be many instances where storage would be incentivised to locate in front of constraints (not behind them) – even with LMP.

The Paper indirectly acknowledges this when it notes that, under the current arrangements, storage behind a constraint may "engage in disorderly bidding in competition with generators… to export to receive the RRP – exacerbating the constraint and causing yet more renewables to be spilt". Storage would only engage in such behaviour if the RRP was high. If the same situation occurred under an LMP regime, the storage asset would only be able to generate and settle at the (lower) LMP, and would therefore be disadvantaged[38] by being behind the constraint. The negative impact on storage from being unable to discharge during high price events could be substantial.

<u>Ability for generators to manage risk due to locational decisions of other market participants</u>

The ESB correctly identified that the combination of congestion charges and rebates does not perfectly mimic the status quo, and therefore introduces a degree of basis risk. However, the ESB did not acknowledge:

- that the CMM does not help market participants to manage the risk of new entrants' locational decisions
- the additional risks of being a step closer towards a full LMP/FTR regime (discussed in Section 4.2).

These risks combine to make the CMM a poor option to manage transmission-related risks

4.3.2 Modified CMM

Our Section 4.3.1 critique of the 'base' CMM is broadly applicable to the 'modified' CMM. We make the following comments in relation to the potential modifications the ESB is considering.

<u>REZ modifications</u>

Under the ESB's proposed 'REZ modifications', only incumbent generators and generators connecting within a REZ would receive the congestion rebate[39]. We acknowledge that this would send a price signal for generators to connect within REZs, or at other network locations with a low risk of congestion. However, this does not negate the undesirable facets of the CMM. We believe that a different type of access regime could provide efficient locational signals for investment without the negative impacts of an LMP regime (see Sections 4.3.4 and. 4.3.3 for examples)

<u>Interconnector modifications</u>

The Paper also flags the prospect of the modified CMM "grandfathering the current transmission network and applying LMPs/FTRs to…new transmission infrastructure" starting with interconnectors, but potentially expanded "to all new intra-regional [transmission] investments"[40]. This would result in the negative impacts of LMP/FTR (see Section 4.2) being realised for new transmission infrastructure. Further, we consider that this would be largely

[37] ESB, *Post 2025 Market Design Options – A paper for consolation, Part B*, 30 April 2021, pp 98-99

[38] Unless it held a sufficient volume of FTR. This would not be the case under CMM, and runs counter to the ESB's logic of locating storage behind constraints more broadly.

[39] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 85

[40] ibid

equivalent to implementing a full LMP/FTR regime with grandfathering arrangements for existing infrastructure. This idea has been previously considered and rejected as part of the AEMC's COGATI consultation. It is also worth noting that connection of an interconnector to a weak section of the existing network may result in a reduction of the volume of grandfathered transmission rights.

4.3.3 Generator transmission use of system charges

We agree with the ESB's self-critique that the GTUOS model in the Paper "is in the early phase of development"[41]. As a result, we believe that the ESB has considered a sub-optimal version of GTUOS when applying its criteria. In particular, although the ESB acknowledges[42] that GTUOS regimes around the world are typically accompanied by a firm level of access for generators (via a transmission network generator planning standard), the ESB appears not to have considered the positive implications on coordinating investment, managing risk and reducing congestion.

Our assessment in Section 4.3.3 considers how a GTUOS regime could work if implemented as a standalone access regime. Attachment A explores how a version of GTUOS could potentially be applied alongside a connection fee regime to deliver equitable outcomes while driving efficient investment in generation and transmission.

<u>Locational signals for investment</u>

If accompanied by an appropriate 'generator access planning standard', GTUOS has the potential to send very strong locational signals. I.e. if TNSPs were required to provide generators with a defined level of firm access (and GTUOS charges were designed to reflect the cost of providing this level of access), then generators would be exposed to the costs associated with their choice of location. This is a strong locational signal for efficient coordination of generation and transmission investment.

<u>Congestion management in operational timeframes</u>

As stated above, where GTUOS is used in other markets, it is accompanied by a generator access planning standard, which provides generators with a defined level of firm access. This defined level of firm access means that generators are only exposed to a known level of congestion. If a new generator sought to locate in a congested area, the network would be upgraded to remove the congestion, and the connecting generator would pay for it via GTUOS.

This resolves the issue of inefficient levels of physical congestion, thereby removing the necessity for additional tools to manage congestion in operational timeframes.

<u>Efficient signals for storage</u>

If storage was willing to <u>not</u> receive firm access, GTUOS charges could be reduced (or potentially removed or made negative, depending on the situation) to reflect the extent to which the storage's connection necessitated network upgrades and/or reduced congestion. However, as discussed in Section 4.3.1, firm access is likely to be materially valuable to storage at times of high prices. Similarly, if the storage asset did not pay for firm access (via GTUOS) or sought to be paid for locating in a way that provided other network benefits, the TNSP could seek contractual arrangements to ensure the storage asset operated accordingly. For example, the contractual arrangements may prevent the storage asset from operating in a manner that impacted the defined level of access of other market participants. If the storage did require firm access, then a GTUOS regime should treat it the same as other generators.

<u>Ability for generators to manage risk due to locational decisions of other market participants</u>

[41] Ibid, pp 86

[42] ESB, *Post 2025 Market Design Options – A paper for consolation, Part B*, 30 April 2021, pp 106-107

An appropriately designed GTUOS scheme would greatly reduce the risk to existing generators of others' locational decisions. In particular, if new generators were prevented from connecting (or were required to operate with network flow control schemes such as runback or tripping schemes) until the network infrastructure required to deliver on the generator access planning standard was complete, then the access of existing generators would not be impacted.

The ESB considers that GTUOS would increase risk to generators as it changed over time. It is not clear to Shell Energy why the GTUOS fees for existing generators would need to change over time. I.e. the cost of new transmission infrastructure could be recovered from new connecting generators (via a GTUOS charge that reflected the cost of the new infrastructure), and potentially consumers (via TUOS).

4.3.4 Locational connection fee[43]

Attachment A provides greater detail on how the concept of a locational connection fee could work. As a result, Section 4.3.4 is intentionally brief.

<u>Locational signals for investment</u>

Shell Energy agrees that connection fees can be used to provide strong locational signals in investment timeframes.

<u>Congestion management in operational timeframes</u>

If the locational connection fee was designed so that the fee covered the costs of doing no material harm to the access of existing generators (effectively providing a level of firm access), then the risk of inefficient levels of congestion would be greatly reduced. As a result, there would be no need for additional congestion-related price signals in operational timeframes.

<u>Efficient signals for storage</u>

As for GTUOS (discussed in Section 4.3.3), the connection fee for storage not seeking firm access could be relatively small, but the connection fee for storage seeking firm access should be calculated the same way as for any other market participant. However, as noted in Section 4.1.3, there is nothing to prevent a scheme (that would operate outside of the transmission access regime) or a commercial contractual arrangement between market participants to incentivise storage and other loads to consume electricity if doing so would reduce the amount of spilled VRE (similar to the ESB's suggestion in the Stage 2 REZ consultation).

<u>Ability for generators to manage risk due to locational decisions of other market participants</u>

The risk of others' locational decisions would be greatly reduced or removed if the connection fee was strongly location dependent, and reflected the costs of upgrades required to maintain the access of other market participants.

4.3.5 Hybrid CMM with connection fee

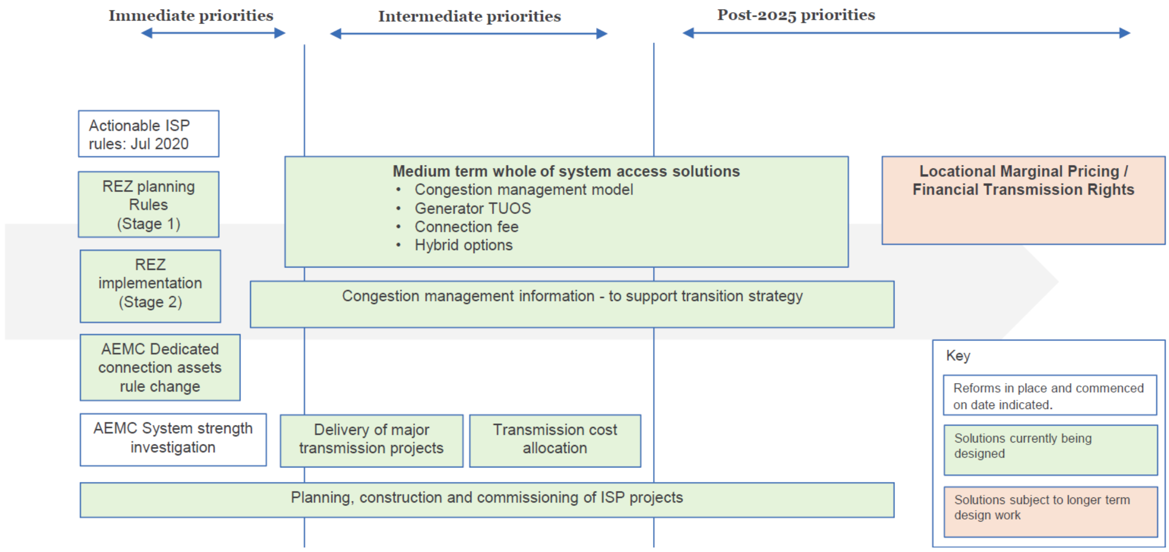
As discussed in Section 4.3.4, we agree that a well-designed connection fee regime could deliver strong locational signals. However, we oppose the CMM, as discussed in Section 4.3.1.

[43] As noted in Section 4.3.3, Attachment A provides greater detail on how the concept of a locational connection fee could work.

4.4 An alternative pathway for transmission and access reforms

As illustrated in Figure 5 below, a foundational pillar of the ESB's proposed reform development pathway is developing medium-term, whole-of-system access reforms as a 'stepping-stone' to LMP/FTR. Shell Energy firmly opposes this approach.

Figure 5: The ESB's proposed pathway for transmission and access reforms[44]



Section 4.4 outlines our rationale for the ESB/AEMC to:

1. cease all work on the medium-term, whole-of system reforms designed as a 'stepping-stone' to a long-term LMP/FTR regime
2. over the medium term, engage meaningfully with stakeholders to develop a workable alternative long-term access regime that does not require LMP/FTR
3. in the near term, focus on developing REZ access frameworks (but not as a stepping-stone to LMP/FTR).

4.4.1 We recommend the ESB reconsiders its intermediate priorities

<u>Medium-term, whole-of-system access reforms are ill-considered</u>

As discussed in Section 4.2, an access regime based on LMP/FTR would have substantial negative impacts on financial markets and physical investment. Stakeholders have repeatedly provided this feedback to the AEMC and ESB.[45, 46]

It appears the ESB has tried to assuage stakeholders by delaying consideration of full LMP/FTR as a "post-2025 priority" (see Figure 5). However, progressing medium-term reforms as a stepping-stone to LMP/FTR is effectively disregarding stakeholder feedback. The ESB has not addressed the underlying issues with an LMP/FTR regime. Therefore, progressing medium-term options that push the market closer towards that outcome is inappropriate.

[44] ESB, *Post 2025 Market Design Program, Options Paper Briefing, Transmission and Access*, 7 May 2021, pp 8
[45] Stakeholder responses to: AEMC, *Coordination of generation and transmission investment implementation – access and charging*, November 2020. Accessed from: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and
[46] Stakeholder responses to: ESB, *Stage 2 REZ Consultation*, February 2021. Accessed from: https://energyministers.gov.au/publications/stage-2-rez-consultation-energy-security-board

Shell Energy proposes an alternative pathway forward

Shell Energy acknowledges the ESB's view that long-term access reform is necessary[47]. Given this view, we recommend a sensible, measured alternative to substantial interim reforms as a stepping-stone to the widely opposed LMP/FTR regime.

The first step of this alternative is to cease work on medium-term, system-wide access reforms. It doesn't make sense to consider 'stepping-stone' reforms unless there is an agreed, clearly defined end goal.

A better use of effort would be to design a long-term access framework that was acceptable to the stakeholders who will be most impacted by it. This forms the basis for the second step of our proposed path forwards: for the ESB/AEMC to work collaboratively with stakeholders to develop a workable long-term access regime. This is distinct from the reform process to date, which has largely involved the ESB/AEMC proposing different variations of an LMP/FTR regime, and stakeholders arguing against these proposals. Table 2 compares our proposed path forward with the reform process so far.

Table 2: Rationalising our proposed medium-term workstream

Shell Energy's proposed medium-term workstream	The reform process to date
The first part of the workstream would be a process to reach broad agreement on the objectives a long-term access regime would seek to meet. As outlined in Section 4.1, we believe that the ESB is currently using imperfect criteria to judge the mooted medium-term reforms.	To the best of our understanding, the AEMC and ESB have not meaningfully engaged with stakeholders to properly define and prioritise the different challenges that access reform is trying to address. Given that the criteria have evolved over time, but the AEMC/ESB's preferred option has remained some version of LMP/FTR, we question the objectivity of the criteria-development process to date.
After reaching consensus on the objectives, the next step would be a collaborative process to develop options to meet them. Importantly, this process would not treat LMP/FTR as the preferred outcome by default, but would instead give due consideration to all credible options. By developing all credible options to be as strong as possible, the AEMC/ESB and other stakeholders would be well-placed to identify the best long-term framework.	In recent years, the AEMC and ESB have overwhelmingly focused their efforts on developing variations of LMP/FTR, with less work on plausible alternatives. The Paper's medium-term reform options provide a recent example of this – the CMM is the cornerstone of three of the five medium-term options. By contrast, the other two options are substantially less developed, and are seemingly adjudged less favourably as a result (see Section 4.3).

There is no rationale to rush through whole-of-system reforms in the medium term

The ESB's view is that:

> *"Given the issues with the stand-alone REZ model, the transition from the interim REZ models to a whole of system solution should occur as soon as the medium-term models can be fully designed and an appropriate implementation schedule occur."*[48]

[47] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 88
[48] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 84

As discussed in Section 4.4.2, we disagree that REZs will suffer from substantial drawbacks over the medium term if they are appropriately designed. As a result, we reject the ESB's argument that there is a pressing need to implement whole-of-system reforms in the medium term.

4.4.2 REZs should be the priority in the short-to-medium term

Our proposed path forward in Section 4.4.1 is an alternative to the ESB's "medium-term whole of system" intermediate priority, and "LMP/FTR" post-2025 priority in Figure 5 above.

In terms of immediate priorities, Shell Energy supports the high-level workstreams outlined in Figure 5. In particular, we believe that the immediate focus should be on developing REZs including the augmentations in the wider network required to facilitate transfer of energy from REZs to demand centres. However, over the medium term, we disagree with the ESB's view that, "REZs need some form of system wide access regime to work well"[49].

Section 4.4.2 provides our high-level rationale for why REZs do not need medium-term, whole-of-system access regime to be effective. For more detail, we encourage the ESB to review our submissions as part of the COGATI consultation[50], the Stage 2 REZ consultation[51] and the recent Central-West Orana REZ access consultation[52].

<u>REZs can be an effective tool for coordinating investment</u>

If a REZ and its access scheme were designed and implemented appropriately, they would deliver a range of benefits to REZ participants and consumers. These benefits would include certainty of access to REZ network infrastructure, improved certainty around connection times and technical requirements, the opportunity to share the cost of system strength solutions (if required) with other REZ participants, and the opportunity to share connection assets (potentially at lower cost than if proponents separately paid for multiple standalone connection assets).

On top of these benefits, state governments have flagged potential contractual support for REZ generators (e.g. the NSW Government's long-term energy service agreements (LTESAs)).

Therefore, generators will be strongly incentivised to build in a REZ compared with elsewhere in the network.

<u>A well-designed REZ access scheme would mitigate the risk of others' locational decisions</u>

One of the ESB's stated concerns is that "the access of REZ generators [could be] degraded by inefficient developments outside the REZ"[53]. However, to the extent that new-entrant generators seek to connect outside a REZ (including as part of a different REZ), appropriate network planning and REZ access schemes can mitigate the risk to REZ participants. Our rationale is as follows.

An effective Integrated System Plan (ISP) and REZ design process would see the network infrastructure in the REZ's primary geographical location complemented (if necessary) by augmentation elsewhere in network (e.g. between the REZ and the RRN) to facilitate power transfer from the REZ to the consumer load centres. When defining the boundary of in-REZ access rights, a good REZ access framework would include all network infrastructure subsumed, constructed or upgraded to facilitate the REZ – even if this infrastructure is geographically distant from the area colloquially associated with the REZ[54]. This would largely prevent other

[49] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 83

[50] ERM Power, *RE: Transmission access reform: Updated technical specifications and cost benefit analysis, 7 September 2020*, 19 October 2020. Accessed from: www.aemc.gov.au/sites/default/files/documents/epr0073_-_erm_power_submission_cogati_interim_report_19oct2020.pdf

[51] ERM Power, *RE: Stage 2 REZ consultation*, 12 February 2021, pp 3-4. Accessed from: https://energyministers.gov.au/sites/prod.energycouncil/files/publications/documents/ERM%20Power%20response%20to%20consultation%20paper%20on%20interim%20REZ%20framework.pdf

[52] Shell Energy. *RE: Central-West Orana RE Access Scheme Consultation*, 30 April 2021, pp 2, 8, 13-14, 16-17. Not yet published. Available on request.

[53] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 81

[54] The REZ access scheme would need to be carefully designed so that, where part of the existing network was subsumed or augmented to facilitate the REZ, existing generators connected to the relevant network assets would also be allocated access rights based on their pre-existing level of access.

(later connecting) market participants 'free-riding' on REZ infrastructure investment, and would therefore protect REZ participants. We note that 19(2) of the NSW EII Act provides for this kind of definition of the REZ boundary.

Appropriate network planning for REZs would avoid inefficient congestion

Another of the ESB's concerns is that:

> *"In the absence of access reform, current problems associated with unanticipated constraints and variable marginal loss factors would affect REZs, just as with other areas of the meshed transmission network. To overcome these issues for investors, a whole of system approach is required."*[55]

As an overarching comment, if the ESB is concerned with overcoming issues "for investors", we recommend that the ESB accepts the feedback from most investors who strongly disagree that a whole-of-system approach is required.

More specifically, we agree that unanticipated constraints and MLF changes have the potential to impact REZs. However, this risk would be largely mitigated with implementation of an appropriate REZ access framework and high-quality network planning. As we have stated in our previous submissions, the ISP (and subsequent REZ design report by the relevant Jurisdictional Planning Body) should 'size' each REZ and facilitate appropriate non-REZ transmission augmentation such that any congestion in the shared network due to the REZ is at an optimal level over the long term. When combined with an appropriate access regime (discussed above), we consider that REZs can deliver high-quality outcomes for governments, market participants and consumers.

Learnings from REZs could help to inform the design of a long-term regime

Another benefit from focusing on REZs rather than redirecting effort to medium-term, system-wide reforms is that stakeholders will be able to learn lessons from the efficacy of different REZ access schemes. This could help to inform the design of a workable long-term access regime, as per the process described in Section 4.4.1.

Interim whole-of-system reforms may have unintended consequences on REZs

Depending on the final design of medium-term, system wide reforms, it is plausible that implementing them may have negative impacts on REZs. For example, consider a scenario where a variation of the proposed CMM is implemented before a REZ is constructed. This would result in FTR (in the form of 'rebates') being allocated to existing generators around the network. Depending on how the REZ is situated in the broader network, it is possible that there may be no 'spare' FTR to allocate to REZ participants. This may result in generators being unwilling to locate within the REZ.

[55] ESB, *Post 2025 Market Design Options – A paper for consolation, Part A*, 30 April 2021, pp 80

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Attachment A A potential alternative access regime

A.1 Purpose of this attachment

This attachment aims to outline how the idea of a locational connection fee could potentially be developed into a workable access framework that would be acceptable to Shell Energy, the ESB, consumers and other industry stakeholders. The primary intent is to focus on the potential new access framework itself. However, in order to address consumer concerns relating to costs being equitably shared, the reform ideas in this attachment also extend to how new regulated network infrastructure (much of which will be required to support state and federal government policy objectives) gets funded. This is consistent with the principles outlined in Section 4.1.2.

This framework in this attachment is not a 'finished product' – there are a range of details that need to be worked through for the idea to become fully developed (see Section A.5). However, Shell Energy considers the concept to be at a point where the ESB cannot dismiss it outright in favour of LMP/FTR. We believe this attachment provides an example of the kind of option that should be explored in depth as part of a consultative process to develop a workable long-term access framework. As discussed in Section 4.4, we consider it likely that, with an appropriately consultative process, our idea could be improved, or another idea could be developed that would be far superior to an LMP/FTR regime. To be clear, we believe this consultative process should occur over the medium term, rather than whole-of-system access reform being implemented in the medium term. Additionally, we believe that, before developing any long-term access regime (including this one), the ESB/AEMC should first collaborate with industry and consumers to reach broad agreement on what objectives the access regime should aim to meet (see Section 4.4.1),

We present more detail in this attachment than the ESB has published to date on the concept of a locational connection fee. This demonstrates our willingness to engage constructively when thinking about a future access regime. We ask that the ESB takes the same approach, with meaningful engagement on alternatives to LMP/FTR. As noted throughout our submission, we observe that engagement to date appears to have discounted stakeholder feedback opposing LMP/FTR.

A.2 Connection fee concept overview

A locational connection fee regime could provide a strong locational signal for co-ordinated investment in new generation and transmission infrastructure. Conceptually it can be thought of as a 'do low harm' requirement (discussed further in Section A.5.2) for new generators seeking to connect to the transmission network.

It would have several steps as follows.

- As part of the application process to connect a new generator to existing or proposed network infrastructure, the applicant (in consultation with the TNSP) would first undertake detailed modelling to identify all scenarios where the new generator could 'do harm' (based on a threshold) to the generators already connected to the transmission network.
- The proponent would then work with the TNSP to assess the physical network augmentation, generation asset capabilities and/or operational behaviours necessary to address these impacts. The TNSP would calculate the cost of undertaking any physical augmentation on the basis of it being a regulated or negotiated network asset paid for by the connecting generator. This calculation would take into account the new asset's capabilities and agreed operational behaviours.

- For example, if the new entrant agreed to be constrained off at all times (via an automated generator runback or tripping scheme) where it would otherwise have negatively impacted the access of existing generators, then the physical augmentation cost would be low. Alternatively, if the new entrant wanted firmer connection, then it would need to bear the cost for physical augmentation that would reduce the number of situations the generator would need to be constrained off/down. The larger physical augmentation required, the higher the cost to the new entrant. In addition to operational behaviours and physical augmentation, the new entrant could potentially enter into commercial contracts with existing generators, under which those existing generators could agree to being 'harmed' under specific circumstances.

- This cost would be the 'locational connection fee' for the new-entrant generator[56]. After the generator agreed with the TNSP on the financial terms of the connection agreement, the TNSP would complete the augmentation (or facilitate any operational schemes) and the generator would be approved for connection.
    - It is possible that a new entrant might prefer to be connected before all the necessary augmentation was completed. In this case, the new generator would need to modify its operations to 'do low harm' to other generators during the period where the broader network augmentation was being completed. The exact details would be negotiated on a case-by-case basis.

There are no 'transmission rights' per se in this type of access framework. Instead, the access regime creates an environment where:

- all generators can be confident that their transmission access won't be materially compromised by new entrants
- new entrants have clarity over locational costs and certainty associated with their connections.

A.3 Funding new/upgraded transmission infrastructure

A.3.1 Privately funded transmission assets

Section A.2 focussed entirely on new-entrant generators seeking to connect to the existing shared network[57]. In this scenario, the new entrant pays for their own connection asset, whilst doing low harm to generators connected to the broader network.

For transmission assets that are funded by a private proponent, we believe it's appropriate for the funding proponent to have a property right to that specific asset (but not the broader network), as per the ERM Power submission to the AEMC's recent consultation on dedicated connection assets[58]. This would result in a slightly different access regime for third parties seeking access to the privately-owned transmission asset (c.f. the rest of the network), because they would need to reach an agreement with the asset owner (in addition to complying with the broader 'do low harm' concept).

Discussing the intricacies of dedicated connection assets and designated network assets is out of scope of this paper. The primary point of the previous two paragraphs was to highlight that it is reasonably easy to apply locational connection fee regime for new entrants seeking to connect to the existing shared network, or privately funded transmission assets. It becomes slightly more complex when considering new regulated transmission

[56] Note that the locational fee would be separate to the normal costs relating to building and connecting a connection asset.
[57] Note that the logic is also applicable for connection to an existing REZ network.
[58] ERM Power, *RE: Connection to dedicated connection assets*, 28 January 2021. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0294_-_erm_power_-_20210128.pdf

infrastructure built to facilitate generation (e.g. REZs), however, the principles of a property right in return for funding network augmentation remains the same.

A.3.2 Regulated network upgrades/extensions

A key concern of consumer groups is that consumers pay for the entirety of regulated transmission projects via transmission use of system (TUOS) charges. This means consumers are allocated all the risks associated with the projects despite generators receiving some of the benefits and creating some of the risks. Under the current framework, the TUOS cost to consumers will increase as more actionable Integrated System Plan (ISP) projects are developed.

As per principle 6 in Section 4.1.2, it is important that the transmission access framework facilitates an appropriate allocation of costs and risks between generators, consumers and TNSPs. For new transmission projects that receive regulated revenue, Shell Energy considers that it would be fair for TNSPs to recover revenue from both consumers and generators, in proportion to the benefit that they receive.

The cost-benefit analysis (CBA) of a project under the regulatory investment test for transmission (RIT-T) process provides a mechanism to establish the proportion of benefits that accrue to consumers vs. generators.

In our view, it is reasonable to expect that a substantial proportion of the benefits of actionable ISP projects will accrue to new-entrant (and potentially existing) generators. Based on the access framework described in Section A.2, once actionable ISP projects are built, new-entrant generators could benefit from them without contributing to their costs. This starts to appear particularly inequitable if the actionable ISP projects are specifically built to facilitate additional generation – especially where the new infrastructure provides little in the way of reliability benefits to consumers.

To address the issue of equitably apportioning transmission costs, Shell proposes the following mechanism that remains consistent with the locational connection fee regime model described in Section A.2. It is effectively a reform of the existing TUOS regime for new-build transmission infrastructure.

- Consider a scenario where AEMO identifies an actionable ISP project. Assume that the project successfully progresses through each approval/development stage, and is constructed.
- During the CBA as part of the RIT-T, require the TNSP to estimate (based on a pre-determined calculation framework) the proportion of benefits that would accrue to customers, existing generators, and new-entrant generators that locate in the network such that they benefit from the project. The Australian Energy Regulator (AER) should carefully review this apportioning of benefits when it assesses the RIT-T. For the rest of this explanation, consider the example of a 30% (consumers) vs. 10% (existing generators) vs. 60% (new-entrant generator) split of benefits
- For that specific transmission project, require the TNSP to have three notional and separate 'cost recovery buckets' - one each for customers (30% of project costs), existing generators (10%) and new-entrant generators that locate in the network such that they benefit from the project (60%). It is possible that costs increase between the finalised RIT-T and the AER approving the contingent project application (CPA). If the cost changes, each cost recovery bucket should be scaled to remain in proportion to the benefits estimated during the RIT-T processes (30% vs. 10% vs. 60%). Cost recovery would work as follows.
    - The TNSP would recover 30% of the project costs from consumers as per regular TUOS charges.
    - The costs in the 'existing generator' bucket (10% of project costs) would be smeared across existing generators that benefit in the form of a new GTUOS charge.

- Initially, the TNSP and/or an underwriter (e.g. a state government) would hold the risk of the 60% of project costs[59]. However, in addition to the 'do no harm' locational connection fee described in Section A.2, the TNSP would be allowed to charge new-entrant generators that would benefit from the project a TUOS fee proportional to the new-entrant's requested access capacity. If there is as much connecting capacity as the ISP/TNSP had planned for, then the TNSP would recover sufficient revenue to cover the entire 60% bucket (for either itself or the underwriter). In the case of a transmission project built to facilitate new generation in a REZ, a government could potentially underwrite the risk of the 60% bucket by guaranteeing a yearly TUOS payment to TNSP. The government could recover these costs via the REZ coordinator recovering costs from generators connecting to the REZ infrastructure. Section A.4 considers the special case of REZs in more detail.
- If a generator retired before the TNSP had recovered all costs in the relevant 'generator cost bucket', the capacity (and accompanying costs) released by the retiring generator would be offered to new or existing generators who wanted to increase their level of firm access. Any residual cost (that would have been paid by the retiring generator) would be reallocated such that generators that did not retire do not have their GTUOS fees increased. There are a range of options for how the residual costs would be reallocated. For example, they could be smeared across all generators, all consumers, or a combination of the two. Alternatively, they could be reallocated to a new cost-recovery bucket for new-entrants that would benefit. This is an example of a design aspect that needs more work (see Section A.5)

Shell Energy acknowledges that the above process introduces complexity and implementation questions that need to be investigated further (see Section A.5). However, it would also deliver substantial benefits. For example:

- There would be a more equitable allocation of costs between consumers and generators to reflect who benefits from new-build transmission infrastructure.
- By default, the TNSP or government underwriter would hold some stranded asset risk due to less-than-expected new-entrant generation. As a result, they would be more incentivised to keep costs down than they are currently. Given that actionable ISP projects/REZs should only be constructed where there is a demonstrated benefit to consumers and/or generators (accompanied by confirmed interest to connect), this risk should be manageable.
- The locational connection fee regime described in Section A.2 means that generators (both existing and new-entrant) can be confident that their GTUOS fees are underwriting value (i.e. they won't be paying a GTUOS fee only to have a new entrant negatively impact their transmission access). We consider that the (effectively) firm access provided by the proposed regime would be of value to generators, and may even encourage investment. As a high-profile (albeit speculative) example, the proposed Sun Cable project values firm transmission access to the extent that it is willing to underwrite substantial new transmission infrastructure. Walcha Link is another example that demonstrates the private sector values firm access to new transmission infrastructure.

Shell Energy envisions that the above process would only apply to new/upgraded transmission assets (i.e. it would not be retrospective). The existing regulatory asset base of each TNSP would continue to be paid for by consumers, via TUOS.

[59] The argument for the TNSP to hold the risk is to disincentivise transmission 'overbuild' during the design phase (because the TNSP would be exposed to the stranded asset risk). However, this may impact the TNSP's WACC, which would ultimately increase the cost of the project. Therefore, a government may be well-placed to take the role of 'underwriter', noting that taxpayers (rather than electricity consumers) would be exposed to the stranded asset risk.

A.4 Vision for how the proposed reforms could interact with REZs

Section A.3 flagged how the proposed access and TUOS reforms allow for government-facilitated REZs as part of the process to fund regulated transmission assets. Section A.4 examines in more detail how REZs could interact with the proposed reforms.

A.4.1 Planning the REZ

Consider a scenario where a government is facilitating a REZ's development via a REZ coordinator. This is consistent with the concept in the ESB's most recent REZ consultation paper[60], the approach NSW is taking with the Central-West Orana REZ, and early moves from Victoria to establish VicGrid as a new REZ-planning entity.

To comply with the proposed access reforms, the REZ coordinator would need to ensure that the REZ was designed so as not to harm the access of generators already connected elsewhere in the network. This is effectively making sure that the REZ and enabling network infrastructure is appropriately sized and has sufficient technical capabilities. If the ISP provides sufficient guidance, and the REZ coordinator works closely with the TNSP, then this should be relatively straightforward.

Note that the REZ coordinator's optimal REZ design may result in congestion for new entrants connecting within the REZ.

A.4.2 Funding the REZ

Assume that the REZ coordinator eventually agrees with the TNSP on the REZ's size, and the physical transmission augmentation/operational behaviour required to facilitate it (so as not to harm the transmission access of generators already connected in the network). The TNSP would calculate the cost of the necessary physical augmentation.

If the REZ is 'regulated' as envisaged by the ESB in its January 2021 REZ consultation paper (i.e. the REZ has been identified "as an actionable ISP project and... has passed a RIT-T"),[61] then costs would be recovered as per the process described in Section A.3.

If the REZ was government-driven (not regulated), then the cost recovered from different parties would depend on the government's appetite to fund infrastructure itself, vs. a desire to recover costs from different parties. At one end of the spectrum, the government could fund the infrastructure in its entirety. At the other end, the government may want to recover all its costs.

Assuming the government wanted to recover costs in an equitable fashion, an independent entity[62] could assess the proportion of the benefits from physical augmentation that would accrue to consumers, existing generators and new-entrant generators to the REZ[63]. The proportion of benefits accruing to new REZ generators would dictate the costs that the REZ coordinator would seek to recover from them (see Section A.4.3). The government could pass on proportional costs to consumers and existing generators by other means. This is consistent with the *NSW Electricity Infrastructure Investment Act 2020*.

[60] ESB, *Renewable Energy Zones, Consultation paper*, January 2021, Chapter 4. Accessed from: http://www.coagenergycouncil.gov.au/publications/stage-2-rez-consultation-energy-security-board

[61] ESB, *Renewable Energy Zones, Consultation paper*, January 2021, pp 5. Accessed from: http://www.coagenergycouncil.gov.au/publications/stage-2-rez-consultation-energy-security-board

[62] Shell Energy expects that the Australian Energy Regulator (AER) would be a suitable entity, given that the assessment of benefit distribution be similar to the assessment the AER would perform as part of a RIT-T for any new-build regulated project (see Section A.3).

[63] If the physical augmentations had passed a RIT-T, then this step would be superfluous, because it would already have been undertaken by the AER as described in see Section A.3.

A.4.3 Establishing the REZ

The REZ coordinator would be responsible for filling the REZ with generators. The ESB has previously suggested an auction or tender process to do so. The REZ coordinator would be free to take this approach, but may consider whether to implement a reserve price to guarantee at least some cost recovery. Alternatively, the REZ coordinator may choose to charge each REZ connectee an administratively calculated, TUOS-like fee designed to guarantee full cost recovery. However, if either the reserve price or the administratively calculated fee is too high, then the REZ coordinator may be left with a stranded asset.

A key point is that the REZ coordinator would be responsible for ensuring it didn't 'overfill' the REZ to the extent that it did material harm to existing generators on the network. Similarly, prior to the auction/tender/similar process, the REZ coordinator would need to make clear to all prospective REZ participants the operational requirements and/or congestion that they would face as part of a REZ designed to minimise whole-of-system costs[64]. If the REZ and facilitating infrastructure was appropriately designed in the first place, Shell Energy considers that these conditions are unlikely to be onerous. If they were not appropriately designed, the REZ coordinator would likely bear the costs of a stranded asset.

Box 1 provides a worked example for the rough order of magnitude that a REZ generator might expect to pay if the REZ coordinator charged a $/MW TUOS fee.

Box 1: Exploring the costs that a REZ coordinator might pass through to generators

Scenario 1

Consider a scenario where a REZ is an actionable ISP project, and passes the RIT-T. The REZ has an average capacity factor of 30%. Capital costs for physical transmission augmentation are $500M. Benefits are split between consumers (25% or $125M), existing generators (5% or $25M) and generators that would connect within the REZ (70% or $350M).

The relevant state government agrees to accept the stranded asset risk by committing to paying a yearly TUOS fee to the TNSP. The REZ coordinator plans to pass on this costs to new generators as they connect via an auction, or via an administratively-calculated fee. Table 3 below shows the yearly cost for generators in Scenario 1A (7% yearly cost recovery) or Scenario 1B (10% yearly cost recovery).

Scenario 2

Scenario 2 is the same as Scenario 1, except that there is a different REZ that is more remote than in Scenario 1 (network capital costs are higher at $800M), but has a higher average capacity factor (35%). Even though the capacity factor is better, the higher capital costs mean that generators pay more to connect to the REZ. This provides a locational signal for proponents lobbying for different REZs.

Table 3: summary of costs to generators in scenarios 1 and 2

	1A	1B	2A	2B
Network capital costs ($M)	500	500	800	800
Costs to be recovered from generators ($M)	350	250	560	560
Assumed yearly cost recovery (%)	7	10	7	10
Yearly cost recovered from generators ($M)	24.5	35	39.2	56
Yearly cost per ($/MW)	7000	10,000	12,000	16,000
Average capacity factor (%)	0.3	0.3	0.35	0.35
Yearly cost ($/MWh)	2.66	3.81	3.65	5.22

[64] As flagged earlier in this section, we acknowledge that a REZ designed with the objective of minimising whole-of-system costs will likely have some non-zero level of efficient congestion.

A.4.4 Ongoing REZ operations

After the REZ-facilitating transmission infrastructure was completed, it would be treated the same as anywhere else on the transmission network for new generators seeking to connect. I.e. new generators seeking to connect anywhere on the network would have to do low harm to all generators already connected to the network (including the REZ generators).

Additionally, until the REZ was filled to its designed capacity, generators seeking to connect outside of the REZ would either be required to either:

- do no material harm to generators that were planned for inside the REZ
- pay the REZ coordinator a TUOS fee equivalent to what an in-REZ new entrant would have paid for taking up the same level of transmission access.

For example, consider a scenario where a REZ was designed for 1 GW of solar capacity, but had only filled 900 MW. A new-entrant solar generator wants to connect outside of the REZ, but the effect of its connection is that the power transfer capability of the REZ during solar hours reduces to 900 MW. In order to do no material harm, the new entrant could either:

- agree to constrain its output in the event that it was causing the REZ to be congested (e.g. if a 100 MW solar farm was to connect within the REZ)
- choose to pay the REZ coordinator a TUOS fee equivalent to the fee a 100 MW solar farm would have paid if it connected within the REZ
- pay for a TUOS fee equivalent to a (for example) 50 MW in-REZ solar farm, and agree to constrain its output if it was causing the REZ to be constrained to below 950 WM during solar hours.

A.5 Outstanding issues to explore as part of a future work program

The ideas in Attachment A have been developed in a timeframe to inform the ESB's mid-2021 recommendations to Ministers. As a result, there are a number of issues that require further consideration. Some of them have been highlighted throughout the course of the attachment. Section A.5 summarises additional issues/questions that should be explored as part of a larger work program, including detailed stakeholder consultation. Section A.5 is not exhaustive, but should provide a useful starting point for the ESB's future thinking.

A.5.1 Questions around central planning

Quality of central planning

Both the locational connection fee access regime and the proposed complementary TUOS reforms are heavily dependent on central planners (AEMO, TNSPs and/or REZ coordinators) doing a good job upfront. For example, if a TNSP gets something wrong when assessing whether a new entrant would do harm (e.g. because of a modelling error or failing to consider enough scenarios), then the new-entrant generators could still cause congestion. Alternatively, the new entrant may be overcharged if the central planner is too conservative.

A tangible scenario would be if the TNSP had not anticipated one or more coal units in the vicinity of the new entrant closing earlier than expected. In this case, system strength may decline to the extent that constraints bind, and existing generators end up being disadvantaged by the new entrant.

A key question is whether the relevant central planners will do a sufficiently good job. If not, how could they be supported to do so?

Who takes on the risk for central planning mistakes?

Even if central planners are highly competent, it seems likely that some mistakes will still be made. As one example, it is important to explore what happens if the TNSP makes a mistake when specifying low-harm conditions, such that a new generator actually does significant harm after it has already made its investment decision. It seems unreasonable for the generator to be required to materially change its operation and/or pay for additional augmentation due to a TNSP mistake. It may be more reasonable for the TNSP to be liable for any additional remediation/compensation. However, this may make TNSPs excessively conservative when imposing 'do low harm' requirements (see Section A.5.2) on new generators. Alternatively, the cost of remediating central planning mistakes could be smeared across the TUOS of consumers if it passed the RIT-T. This is effectively what happens under the current cost recovery framework.

Apportioning benefits to consumers, existing generators and new-entrant generators

The TUOS reforms covered in sections A.3 and A.4 rely on an independent entity (potentially the AER) assessing the proportion of benefits that accrue to consumers, existing generators and new-entrant generators. For this to happen, the RIT-Ts (or equivalent CBAs for non-regulated REZ developments) need to be of a high quality. This will be more difficult for assets like interconnectors or meshed REZs compared with radial REZs. There will undoubtedly be arguments over how the benefits are split. With this in mind, it may be useful to develop additional CBA guidelines for this purpose.

A.5.2 How to implement a 'do low harm' framework

Defining 'low harm'

Throughout this attachment, we have used the concept of 'doing low harm' to existing generators. From an electrical engineering perspective, a true do no harm approach would require extensive system modelling under numerous power system conditions which would include forecasts of future generation and load connection including the type of connecting system, i.e. synchronous or asynchronous. The required level of modelling to cover all conceivable conditions would be challenging to achieve. Therefore, a 'do low harm' principle is more appropriate than a 'do no harm' principle. However, it is difficult to define.

There are multiple different types of transmission-related 'harm' that a new entrant can do to an existing generator. These include increasing thermal congestion, impacting fault level, impacting oscillatory and transient stability, and affecting revenue due to changes in MLF. Any 'do low harm' framework requires thresholds to be defined for each different type of harm. These thresholds require careful consideration.

The definition of these thresholds impacts the practicality of a 'do low harm' assessment for new-entrant generators. Shell Energy anticipates that there would be an increased (but not prohibitive) modelling requirement for new connections. This is likely to add time and/or cost during the connection process. However, connection timeliness could potentially improve overall due to a lower number of connection applications outside of areas (e.g. REZs) where new-entrants can do low harm without substantial physical augmentation and/or restrictions on operability.

Identifying 'do low harm' conditions for specific assets

The generation patterns for some assets (e.g. solar farms) are relatively easy to predict, whereas the generation behaviour of other assets (e.g. wind farms) has much greater variance. This may make it difficult for a TNSP to assess the likelihood of 'harm' prior to connection, and could result in excessively high or low connection fees. It may be necessary for contractual arrangements between the TNSP and generators to ensure operational decisions don't negatively impact existing generators. This requires further consideration.

Trade-off between investment certainty and network utilisation

There may be a degree of tension between providing investors with certainty that their access won't be adversely impacted by others' locational decisions, and minimising total system costs (which would require a degree of 'efficient' congestion). As a result, a 'do low harm' model may lead to more physical network infrastructure than if there was a different approach whereby there was a higher acceptable level of congestion. However, this could likely be addressed by carefully considering the definition of 'low harm'.

A.5.3 Miscellaneous

Potential conflicts of interest

The do low harm framework for new-entrant generators is based on an assessment by the TNSP. However, the TNSP has an incentive to:

- require excessive physical augmentation, if it is the entity undertaking (and getting paid for) the work
- require excessive technical capabilities for the new generator, as this would allow the TNSP to operate the network more easily, but at the cost of the new generator).

To address these issues, it is worth considering whether:

- there could be an appropriate mechanism to challenge the do low harm requirements
- the provision of any physical augmentation could be contestable, so that the TNSP is not the monopoly provider
- an entity that is independent of the TNSP should be responsible for assessing/reviewing a new entrant's requirements to meet the do low harm threshold.

What happens to the 'spare' access when generators retire?

As mentioned in Section A.3.2, consideration needs to be given to what happens to 'spare' network capacity when a generator retires. The answer may be different depending on whether the cost of the transmission infrastructure built to accommodate the retiring generator had been recovered from that generator or initially allocated as a grandfathered right. For example, if the costs of the network had been fully recovered from the retiring generator, would the retiring generator be able to on-sell their capacity rights? Alternatively, would this capacity be shared amongst existing generators (which would effectively increase the firmness of their access), or would it be made available to a new-entrant generator(s) with payments by this generator used to reduced costs paid by the other generators? If the retiring generator was paying costs on a yearly basis, could the yearly payment simply be transferred to the new connecting generator(s), potentially at the same rate? For any of these options, should there be a price on this spare capacity? If so, how would the price be determined and any additional revenue be distributed (e.g. to consumers as a TUOS reduction)?

Sharing the cost of 'efficient' congestion

As part of its Stage 2 REZ consultation, the ESB raised the concept of preventing 'winner-takes-all' outcomes within REZs by introducing a revenue sharing scheme between REZ participants during times of congestion. It would be worth investigating options to apply this concept more broadly as a complementary measure to a whole-of-system connection fee regime.