Energy Security Board
Level 15, 60 Castlereagh St
Sydney NSW 2000

Post-2025 Market Design

Bright Sparks is grateful for the opportunity to make a submission in response to the *Post 2025 Market Design Consultation Paper* (**Consultation Paper**).

Bright Sparks is a community for engaged, motivated and passionate young people working in clean energy across Australia. Our members are the future generation of leaders to inherit the National Electricity Market (**NEM**). We already actively work for retailers, generators, government bodies, start-ups, advisory organisations, academic groups and NGOs or think tanks and play a role in developing, operating and reforming the NEM in our day-to-day. We bring creativity, vision and accountability to the work we do and the Consultation Paper process.

Bright Sparks supports the need for long-term strategic design and vision for the NEM, as outlined in the Consultation Paper and each market design initiative (**MDI**). We emphasise the systemic and integrated nature of the NEM and the need for a systematic and integrated approach to reform, guided by core principles. Based on the current AEMC rule reform process, the recent activism of states away from COAG and the rapid shift of new technologies and business models, there is a risk the NEM design process will be ad hoc, political, reactionary and will not even be purpose-fit for the NEM in 2025, let alone 2040.

Principles

Bright Sparks propose key principles that should overarch each MDI and the design process as a system:

- **Emissions objective** - emissions reduction should be central to market design, implementation and operation. Emissions centrality is even more important in the absence of Commonwealth action to reduce economy-wide emissions and the inadequacy of Australia's Paris Agreement target to deliver decarbonisation in the timeframes needed to prevent irreversible climate change. In 2025 and beyond, the emissions impact of our electricity system will be just as important as price, reliability and security. Meaningful emissions reduction must be 'front-loaded' in the next 10 years and not delayed any longer.
- **Intergenerational resilience** - we are the next generation of leaders to inherit the NEM. We have already witnessed the impacts of extreme heat, fire and flood on our energy infrastructure in recent years and the inadequacy of our current response mechanisms. Physical and market design must build in climate resilience for the likely climate scenarios the NEM will need to withstand in 2025 and beyond. While the Consultation Paper is focused on increasing integration, which we support, we also encourage design thinking on a modular and localised scale to ensure physical systems and communities are resilient to inevitable climate futures and can access enduring security and reliability of low emissions supply. All modelling must also include climate scenarios and variable emissions trajectories.
- **Enables technology** - the NEM is currently dealing with the consequences of reactionary reform in response to new and emerging technologies. NEM mechanisms need to accommodate scalable technologies available today and anticipate the integration of technologies that will be low cost, low emission and scalable by 2025 and beyond. Such technologies are not limited to generation but include system strength services, load shifting tools and dispatch management. Government initiatives to support new technologies should be enabled by responsive and appropriate reform.
- **Digital innovation** - the NEM will be increasingly decentralised and have a diverse hive of market participants in 2025 and beyond. Market design must facilitate transparency, information disclosure and be data driven to enable all participants access to the information needed to promote competition, overcome information asymmetries and enable digital technologies, business models and multi-directional market operation.

- **Equity inclusion -** historically, the NEM has operated as quasi-monopolies with vertical integration, semi-state ownership and domination of products and services by the 'big 3' incumbent gentailers. As market dynamics shift and participants diversify, reforms must enable equity in participation and benefit-sharing by allowing new market entrants to generate and sell electricity or system services, while ensuring competition and consumer protections are upheld. Equity must also be considered when allocating market costs i.e. transmission infrastructure, to ensure cost recovery is not disproportionately borne.
- **Review and responsiveness -** we encourage the ESB's ambition and vision for the NEM beyond 2025. From a system design perspective, regular reviews re-evaluating and adapting the design approach in the lead up to 2040 are necessary to ensure alignment with other policy reviews and changing market dynamics. The MDIs should be developed holistically and with necessary political support to limit developing in silos or ultimately being shelved instead of as part of a consistent system wide approach.

Vision

Significant effort is needed to decarbonise our NEM and meet the principles outlined above. We believe the energy industry has the skills, capability and motivation to deliver. The Consultation Paper outlines issues the NEM currently faces however lacks a clear vision of what the NEM needs to look like in 2025 and beyond. Bright Sparks propose 3 cornerstones for NEM reform for the MDIs to be enduring, relevant and impactful in the future.

- **Decarbonisation target -** commit to a politically-endorsed date to phase out fossil fuel generators, with a trajectory based on highest emitting generators. While we know a target requires a political mandate, the assumptions in the Consultation Paper may shift dramatically if an ambitious science-based emissions reduction target were introduced by the Commonwealth. We propose the following actions:
    - National Electricity Objective (**NEO**) amended to include emissions reduction;
    - coal completely phased out by 2030;
    - no new gas supply and generation from 2020.
- **Sensible market intervention -** we have been educated into the NEM during a period of privatisation and "free" market development, to some extent. The Consultation Paper suggests increased market intervention in some MDIs. We consider the market is capable of delivering market objectives when there is a clear framework and guiding law or policy to respond to. The market has been stifled by ad hoc reform, inconsistent policy changes and the stepping-in-and-out of government in different markets. Government intervention should be limited to where it's essential and predictable when done - governments play an essential role in the system but effort may be better placed in setting targets and frameworks for the private sector rather than empowering government bodies as active participants.
- **Energy integrated in the economy -** the Consultation Paper cannot be developed and consulted upon in isolation from a vision of the wider economy in 2025 and beyond. There is a risk that stakeholders are limited to incumbent market players whose best interest is the sale of increasing volumes of electricity. The physical and market-based NEM design needs to account for the location and load of heavy industry, agriculture, the electrification of transport and regional communities in 2025 and beyond and the necessary decarbonisation across these segments of the economy. State and local governments in NEM jurisdictions should have active voices. The assumptions of where and how and why we use electricity must be questioned. There is a risk the MDIs and NEM reform will be developed and implemented in an energy industry vacuum and not be purpose-fit for the entire economy in NEM states beyond 2025.

Developing the MDIs

Bright Sparks provide our perspective on the shifting nature of NEM demand and supply in response to MDIs B, E, F and G. For each MDI we give an overview of how each principle highlighted above may be addressed, then plant high level ideas for ESB consideration in response to selected questions in the Discussion Paper. On the following page is a table assessing each MDI against each principle.

Any questions about our submission should be addressed to bright.sparksAU@gmail.com. We look forward to further participating in the ESB's MDI process and following the Consultation Paper next steps.

Kind regards

Bright Sparks

Table 1: Bright Sparks MDI Assessment: We assess how our principles need to be applied in each MDI.

Principle	MDI B: Ageing thermal generation strategy	MDI E: Two-sided markets	MDI F: Demand flexibility and DER	MDI G: Transmission access and COGATI
Emissions objective	The latest research now shows that we must exit the coal industry by 2030, due to the magnitude of the climate crisis.	Increased, robustly-integrated demand-side participation should result in significant emissions reduction.	DER is already contributing to the provision of reliable, clean, affordable energy and these benefits need to be considered when considering the speed of integration into the market.	ISP scenario modelling should have greater centrality of climate resilience and climate scenarios.
Enables technology	The transition from thermal generation will be driven by market forces. Where possible adopt technology neutral / agnostic approach that facilitates the transition to emerging more efficient technologies and is not biased towards existing technologies.	Diversified revenue streams and more options available to consumers should incentivise further uptake of DER.	Integration of DER into the market should encourage innovation.	ISP focuses on large scale generation and transmission infrastructure. Non-network solutions to be considered in CBA and prior to investment decisions ISP review must adapt priorities in response to new technologies.
Digital innovation	Replacements for existing thermal generation should consider decentralised/ community power generation.	Power electronics interfaces, virtual power plants, increased appliance interconnectivity and emerging retailer models will increasingly contribute to a grid that addresses the energy trilemma.	Ensure interoperability of technologies.	Maximising network assets will require digital innovation through dispatch controls, hedging and load shifting to manage variable constraints and MLF/LMP.
Equity inclusion	Incumbents must not be favoured during and following the transition. Provide support for people/communities that are affected by closure of existing generation, support skills transfer and reskilling during the	Regulation, licencing and standardisation for aggregators and intermediaries must equitably share costs and allow for inclusion of low socioeconomic consumers.	Access to providing DER services should not be limited. Intermediaries need to have fiduciary duty.	RIT-T cost recovery model risks passing on network costs to consumers while generators may receive increased benefits.

	energy transition.			
Inter-generational resilience	Existing generation should prioritise deploying renewables and supporting technologies such as storage in replacing existing thermal generation fleet. Investing in new thermal generation risks massive sunk cost that must be managed or closed by future generations.	Increased electricity market participation should allow 'prosumers' to make better-informed energy choices with more robust financial and system outcomes.	Design with the increasing frequency of climate related disasters in mind and consider that DER in microgrids is a great option for future-proofing supply in vulnerable communities.	Climate risks and scenarios should have greater centrality in network planning, including through the RIT-T. We support the integration of the Electricity Sector Climate Information Project into all future ISP work.

MDI B: Ageing Thermal Generation Strategy

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

- The effects from a transition away from thermal generation are unavoidable and must be planned for. As clean energy continues to become more affordable, new and existing thermal generation will be excluded due to high cost. The extent of reliability benefits of having coal generation sourced baseload power are debatable due to the delays in ramping up generation from such plants and the replacement with new technologies offering similar services or supply with lower emissions.
- The risks can be mitigated by the proposed planning schemes. Renewable energy, supported by battery storage, have proven to be readily deployable at large scale.
- To maximise environmental benefits whilst limiting disruption during the transition, closure of thermal generation should prioritise the heaviest polluters (e.g. Without supporting mechanisms, black coal generators will be closed down ahead of more polluting brown coal generators, because running costs of brown coal plants are lower).

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

- We agree that the transition away from coal is inevitable with the latest research showing that we must exit the coal industry by 2030. Recently, governments are struggling to support aging power plants. Gas has been proposed as a priority 'clean' solution, but gas is not a transition fuel and comes at additional cost.
- Ultimately, any additional costs compared to a scenario where black coal plants exit would be borne by electricity consumers. Research from ARENA shows that additional cost would be small and temporary. Furthermore, the economic impacts from climate change are massive, with the most recent summer of bushfires costing Australia over $100 billion as well as devastating our environment and the lives of many Australians.
- Costs of renewables continues to decrease, and costs will be far lower in the long term relative to thermal generation. $/MWH is expected to increase minimally relative to the carbon mitigation benefits. The impact of a transition to renewables on consumer cost will be dependant on the price of natural gas, as shown in the table below. The cost of a renewables transition relative to gas is higher in the case where gas is at $3/GJ, but this price has not been regularly seen over the past decade.

Incremental cost increases as a function of the RE share (calculated from Series 1).

	Incremental increase (average $/MWh) per 10% RE share increase		
RE share between	$3/GJ gas	$6/GJ gas	$9/GJ gas
0 and 80%	2.78	0.81	0.86
80 and 90%	5.62	5.37	4.24
90 and 100%	7.60	5.43	5.91

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

- **Capacity remuneration mechanisms**: New generators must be available immediately after closure of thermal generation. To assist with this, generators should be rewarded for assets that are available for dispatch whenever the aggregator needs it and penalised if not available when called upon.
- **Locality specific notice periods:** Notice periods should be evaluated based on local criteria including grid integrity, availability of replacement capacity, etc. rather than a fixed notification window. Note

that flexibility of these windows should be an aid to prepare for transitions, not an excuse to delay arranged exits.

- **Transparency in closure plans:** Local incentives for new generators should be provided in the vicinity of thermal generators in advance of known upcoming closures. The plans for thermal generation exits must be transparently publicised to avoid undue advantage to incumbents.
- **Transition of workers:** Workers displaced due to thermal generation exits must be assisted through the transition (e.g. adopting soft criteria in auction schemes or other government grants that support reskilling workers from incumbent generation could be a low cost way of achieving this - a number of gentailers operate across both thermal and renewable generation so they can be well-positioned to assist in skills transfer). Since not all will want to or be able to transition to new renewable technologies, reskilling paths should be diverse.
- **Incentives for community production:** Replacing capacity isn't just about replacing thermal generation with large scale generation. For example, the "Emerging Renewables Program", was initially intended only for large scale, but a 6MW virtual power plant was included (led by Solarhub), which means that the community itself can provide some of that new capacity and directly earn its benefits.
- **Staffing and resources for new generator tie ins**: As a need for new capacity arises, there will be an opportunity for new generators to enter the market. Evaluate approvals for tie-in to existing power distribution. Ensure that incumbents don't have undue market power. An example of strategic tie ins is the Renewable Energy Zones (REZ) programme in the NSW's Central-West Orana, New England and South-West regions
- **Focus on renewables over new thermal generation:** As discussed, above, the cost to consumers from a transition to renewables will be dependent on the gas price. Even if the price of gas dips temporarily, excessive investment in gas infrastructure would be ill advised. Given the historical variability of gas prices, and predictions that they will remain high in the long term, new gas generation risks major sunk costs that future generations will be forced to manage or close at massive expense.

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

We support the initiatives proposed in the ESB discussion paper. Specific comments include:

- **Regulated or negotiated arrangements with thermal plants**: Negotiated arrangements are recommended provided that they do not give an unfair advantage to the incumbents. These negotiations should be as transparent as possible.
- **Payments made as withheld deposits:** We support this approach if companies are exceeding their notice periods, but note that these payments must be substantial if they are to be effective.
- **Contingent scenario planning**: Scenario planning should be done for unplanned events, but the focus should be on a concrete strategy for the exit of existing thermal generators. Australia has a history of uncertainty in its policy which has made it difficult to attract investment in many instances. When establishing a transition to new generators, the regulator should strive to provide confidence that thermal generators will exit as per the communicated plan. We note the need to strike a balance between providing concrete long-term incentives and stable policy approaches to provide the certainty needed to facilitate investment while maintaining adaptability and including contingency planning for unplanned scenarios etc.

MDI E: Two-Sided Markets

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

Opportunities

- **Increased competition:** greater demand-side participation from consumers will precipitate greater competition among retailers, as users with the required sophistication for load shifting are now preferring more efficient pricing structures (i.e. Flow Power, Amber Electric etc), allowing customers to access the true cost of electricity.
- **Diversified revenue streams:** additional revenue streams may be unlocked or reduced energy expenditure will result for consumers that participate as 'prosumers', noting intermediaries will seek commission or administration charges.

Risks

- **Availability shortfall**: if a certain amount of demand response (**DR**) is being relied upon, especially in difficult circumstances like generator or transmission outage and peak load coinciding with high temperatures, and the required amount cannot participate when required, grid security could be compromised. This risk can be mitigated through a capacity remuneration mechanism (**CRM**); see Question 3 below for details.
- **Equitable access to participation**: all electricity consumers should have equal opportunity to participate in DR. Competition between aggregators and intermediaries should be facilitated and transparent, to avoid industry incumbents disproportionately leveraging their weight to exploit this capacity. Consumers must be fairly compensated by their DR participation provider, which demands an adequately visible and functional market in contrast to the current default of bilateral contracting, in which information asymmetry can lead to energy users being exploited. Furthermore, other reforms e.g. network tariffs must be considered in conjunction for consumers unable to install DER on their own premises (renters, apartment owners).
- **Intermediary/aggregator regulation:** remuneration needs to be efficient and reflect the real value of the service provided by the asset owner. DR aggregators could hypothetically game or collude to set unfairly high fees or margins, which could be mitigated through an intermediary licence similar to an Australian Financial Services Licence (AFSL), but less expensive and with a higher regulatory burden to combat the risk of 'cowboys' (recalcitrant, unco-operative parties) by encouraging competition. Aggregator choice will have a large effect on the value available for consumers to derive from their DR, and this will add to the complexity of choice the consumer must make, which is particularly difficult in an emerging market. Additionally, market participation arrangements between aggregators and retailers may exacerbate retailer lock-in and harm retail price competition.
- **Over-reliance on competition and efficient markets to drive investment will exclude large portions of available resources**: market participation may not be a major value stream for prosumers in all cases; rather serve to be a value stream to supplement the primary self-sufficiency/autonomy/environmental/bill reduction benefits. Consumers will have a choice as to how to use their system, and insufficiently valued services (particularly for contingency and system security) may lead consumers to make the decision to exclude their system from participation in these services. For example, providing system security support that uses a lot of energy (i.e. RERT) may reduce the ability of their system to provide backup power, which they may value higher. Other energy services being withdrawn from the market during a potential blackout event (e.g. DR not responding to peak pricing coming up to a potential LOR3 event due to charge-holding for a blackout) could also prove problematic.

- **Long-term vs short-term investment signals:** DER systems that provide multiple value streams to the consumer have the capacity to enter and exit demand-side markets freely, with relatively small economic impact. Longer term changes in the DER landscape or the market may lead to large changes in participation, with significant impacts on longer-term investments. For example, a single blackout event could cause an exodus of DER from contingency support as consumers discover the value that backup power could provide them.

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

- **Consumer sophistication and load flexibility**: if sophistication and load flexibility are poor (i.e.industrial processes that take significant time to ramp down), some users may be disincentivised to scale back on operations or production if the financial case is insufficient, which means the market may not be able to access significant latent DR potential. Older technology times could also be outperformed by power electronics interfaces, which is noteworthy if this excludes significant capacity from participation.
- **Complex participation requirements**: if registration, administration, monitoring, connectivity requirements are difficult to navigate, smaller users may struggle to effectively participate. The point on licencing in Question 1 of this section can be extended to address this.
- **Load size**: smaller energy users risk exclusion and will need to aggregate to outsource dispatch and make participation worthwhile financially.
- **Consumer desire for autonomy:** in small scale trials of system co-optimisation, consumers often reacted negatively to their system behaving in ways that were difficult to explain, or not directly beneficial to them. Consumer education will be increasingly important to ensure consumers understand the implications of increasingly sophisticated behaviours.
- **Consumer risk aversion:** in a stable market, demand-side participation would provide a consistent additional value stream that would improve system economics. However, consumer choices are never purely economic, and are often guided by lower probability but higher impact scenarios. Negative experiences, which are particularly likely in a nascent market with maturing technology, will likely have a large impact on participation.

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

- **Capacity remuneration mechanism**: DR participants could be rewarded for availability, in addition to the payment awarded for the volume of 'negawatts' (a unit of demand reduction, functionally equivalent to a unit of generation) provided. If the asset is not available for dispatch whenever called upon by the aggregator or market operator, financial penalties would apply. This incentive for capacity provision could make a stronger business case for accelerated uptake of DR behaviours.
- **Lower-risk consumer products that include market participation**: current system design assumes that consumers that would like to participate in markets are willing to be exposed to higher risks. Prime examples of counterparties taking full risk include Tesla's energy plan (retailer takes FCAS risk) and sonnenFlat, highlighting retailer incentive to maximise revenues of the asset. Further trials exploring the de-risking of consumer decisions that still incentivise active participation should be explored to ensure that participation is not just restricted to those consumers with the resources to understand the full implications of their decisions (and the need to protect against consumption during VoLL events).

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

- **Education programs**: independently-produced resources and guidance documents should be developed to help less sophisticated potential DR participants like residential consumers, in addition to all current and potential commercial and industrial actors, to assess their options and make informed decisions, balancing the financial interests of the user and the benefits to the development of the system.
- **Licencing, regulation and standards**: further to licencing comments in Question 1 of this section regarding consumer financial protections, consumer data and privacy must be protected under the ACC Act 2002.
- **Equitable cost-sharing**: Low socioeconomic areas that are disproportionately affected by high electricity costs will typically not have sophisticated access to demand-side participation. This should be considered in the context of transmission infrastructure and pass-through of network costs to fewer customers if wealthier customers are self-supplying (i.e. addressing the cross-subsidy of network charges disproportionately borne by customers without DER access, and a ‘social tariff’ to supplement concessions and rebate programs; a special electricity rate for eligible customers e.g. low-income, fixed-income pensioners, life-support customers, to maintain basic quality of life and preserve their independence).

MDI F: Valuing Demand Flexibility and Integrating DER

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

- **The existing operations of DER:** Bright Sparks has found that the existing role being played by DER has been largely ignored. We already have residential, commercial and industrial DER participating in the market, as unscheduled loads, FCAS providers (for which short-term guidance was released in late 2019 by AEMO), providers of network services (through DNSPs), RERT participants and through off-market contracts. It may be useful for the Post-2025 Market Design to examine how innovative participants, and intending participants, are operating (or intending to operate) in the market today and the benefits/drawbacks of these DER incorporation models in the context of the future grid.
- **Role of intermediaries and retailer arrangements:** contingencies need to be made for the types and roles of intermediaries, e.g. installers, retailers, in DER participation in the market. In general, the retailer is still the 'bulk energy' provider for customers, but third-party providers for ancillary services, solar trading and/or demand response are emerging. The role of this intermediary can be carefully consolidated, and may be given to the 'Trader' participant in the two-sided market work stream while also ensuring that this role has some flexibility into the future to adapt to the unknowns in the market/s design.
- **Future-proofing:** DER should be incorporated into a market that encourages innovation and competition to develop the best technologies and ownership models. The place for new technology to expand the capabilities of currently used aggregation models such as virtual power plants and vehicle to grid integration should be considered.

2. **In the next phase of the project, the ESB proposes focusing on development of a detailed DER market integration proposal. What are the most important priorities for DER market integration? We are considering combining the DER integration and two-sided markets workstreams, or elements thereof. Do stakeholders have suggestions on how this should be done?**

- **The purpose of DER:** further consideration should be given to the purpose of DER market integration and the benefits it will (and already is) providing, including enabling a greater range of technologies to contribute to the provision of reliable, clean, affordable energy.
- **Equity:** access to participate in providing DER services to the market should not be limited to only those that can afford it and benefits from providing DER services should be shared equitably. Intermediaries (whose role has been discussed above and in the two-sided markets response) will need to have fiduciary duty and many new services provided by intermediaries in the DER space will not come under the existing National Energy Consumer Framework. Bright Sparks sees a place for a flexible governance framework such as an AFSL for DER to ensure that DER integration is inclusive.
- **Climate resilience:** in line with one of the overarching principles of Bright Spark's response, DER market integration needs to consider future challenges from factors intrinsic to the market design as well as external factors. The increasing frequency of climate related disasters, including the devastating bushfires of Summer 2019/20, will pose threats to supply and building local capacity through incorporating microgrid structures with a high penetration of household/commercial level DER will have a key role in ensuring security of local supply during these events.

NB: Bright Sparks believes that the two-sided markets of the future will be inextricably linked to the grid support services provided by DER and supports the combining of the two workstreams by the ESB.

3. **How can we ensure owners of DER can optimise the benefits of their DER assets over time as technology and markets evolve? How do we time reforms to manage the costs and benefits for DER owners?**

- **Price points for DER:** remuneration given to owners of DER for providing system services needs to be in line with the value that DER is providing to the grid at a particular point in time. Employing local network pricing will also be important here to ensure network charges are cost reflective, e.g. currently if you generate solar and your neighbour consumers it, your neighbour pays full distribution and transmission network charges even though the electrons only used a few meters of the network. This will ensure that the use of the services provided by DER is not discouraged, further optimising benefits to both DER asset owners and those who utilise DER services.

- **Consumer/owner education:** The need for and mechanisms for consumer education was addressed in Bright Spark's two-sided market response and also has applicability in the context of ensuring owners of DER can optimise the benefits of their assets. Owners will be required to make a number of decisions relating to how their DER will participate in the market and will be required to fully understand these decisions (or intermediaries will need to be acting in the best interest of asset owners as per the equity considerations above).
- **Interoperability:** Considering the significant upfront costs of many DER assets, interoperability of assets is important to ensure that purchases made now do not have limited functionality in the future when combined with newer technologies. Asset owners should also have some choice in how their assets are operating together and knowledge around how future asset purchases are likely to affect any assets they currently hold. Mechanisms to enable asset interoperability should be explored as part of market reforms.

MDI F: Transmission Access and the Coordination of Generation and Transmission

1. **The second ISP has now been released. Do you have any comments on how its implementation can be made more efficient and timely?**

- **Reducing assessment time and costs beyond the RIT-T -**
  - RIT-T reform should be designed to limit the assessment time and cost, with the assessment itself ultimately designed to minimise network costs passed onto consumers.
  - Proposed reforms seeking to amend the RIT-T should focus on streamlining the assessment process and cutting out existing redundancies (i.e. limit multiple feedback loops and duplicative planning stages) while retaining flexibility for assessment criteria and investment need against non-network alternatives over time.
  - The current reform agenda risks further complicating chapter 5 of the NER through multiple RIT-T pathways: current projects subject to the transitional ISP 'sandbox', new actionable ISP projects, non-ISP projects and projects subject to a varied RIT-T due to state derogation may all undertake the RIT-T in different ways, which may deliver different outcomes, costs and benefits.
  - We are concerned that assessment complexity will only add to increased assessment time and cost, instead of efficiency. Rather than niggling around the edges of existing slow and expensive RIT-T through reform or derogation, we recommend the ESB consider the utility of RIT-T as a cost recovery mechanism for network infrastructure at a high level and for future durability.
- **Broadening benefits and diversifying cost recovery -**
  - The RIT-T is a cost benefit assessment designed to deliver a specific outcome: maximise the present value of net economic benefit to all those who produce, consume and transport electricity (NER, 5.15A.1(c)).
  - As set out in response to other MDIs, production, consumption and transport of electricity is shifting. We consider more diverse criteria may need to be incorporated into cost-benefit analyses, including policy drivers, and greater weighting to non-network solutions from the outset.
  - The current RIT-T assesses net market benefit so treats producer and consumer surplus equally. An alternative approach could be to weigh the consumer surplus higher so an option that gives $10 benefit directly to consumers is better than one that gives the same $10 benefit to industry and with the intention to 'trickle down' benefits to consumers.
  - A shift in benefit distribution may need to be reflected in cost recovery (i.e. increased cost pass through proportional to benefit received), however we think the overall funding model for network infrastructure could be reconsidered to reduce the capital base recoverable from consumers (see comments below).
- **Adaptability and limiting costs of review consequences (real 'no regrets') -**
  - The Integrated System Plan (**ISP**) is designed to be a live, adaptable and fit for purpose policy instrument to respond to large scale transmission infrastructure needs that meet the changing nature of NEM demand and delivers cost savings to consumers.
  - Sequencing and cost factors must be taken into account - ISP review every 2 years must take account of the 2-3 year lead time to pass the RIT-T and the associated transaction costs, particularly where governments are providing underwriting to NSPs (i.e. Humelink).
  - If projects are removed/scaled back in the ISP (for whatever reason), proponents should not be compensated for costs incurred to date.
- **Clear roles for private vs public sector -**
  - Network services providers (**NSPs**) are a mix of public and private entities across the NEM. States are actively involved in most Actionable ISP projects - however state involvement

should be determined on a lowest cost basis i.e. should states be responsible for facilitating projects passing the RIT-T then NSPs/contractors/private sector fund construction?
  - Funding and ownership of network infrastructure should also be considered, which is currently limited by network asset classification under the NER i.e. could private capital (debt/equity) not sourced by an NSP fund and own network assets and what impact will this have on RIT-T cost recovery?

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

- **Responsiveness for economy wide NEM capacity need -**
  - We acknowledge AEMO has undertaken robust modelling for the ISP. However, we query the need for the projected overall network capacity set out in the ISP.
  - We would prefer to see an economy wide approach adopted where non-network solutions, DER and relocation of industry proximate to generation were alternative solutions to continuous build of expensive and long lead time network infrastructure.
  - At a minimum, AEMO's review process must be agile enough to revise project need in response to shifting demand and market dynamics. See our comments on MDI E & F for how we think the DER market may look and our comments below on congestion.
- **Testing the cost recovery model and increasing accountability -**
  - The RIT-T cost-recovery model is not-fit for purpose for ISP and REZ projects as there may be additional beneficiaries (i.e. generators).
  - If the current cost recovery model for shared network assets is retained, there is a significant risk that costs of network infrastructure will be inequitably passed onto consumers without the benefits that new and existing generators receive being adequately priced (noting our comments on COGATI below and broadening benefits above).
  - In addition, the current incentives for over-investment increase the risk of unnecessarily inflated capex costs being ultimately passed through to consumers. We consider this highly problematic in the context of the proposed transmission build in the ISP and emphasise the need to consider how incentive structures and cost-recovery approaches can be adapted to better achieve a balance between appropriate price pass-through and over-investment.
  - In the context of DER, there is also a risk that network costs are disproportionately shared by consumers i.e. users that self-supply through solar/DER may not pay network charges so users without solar may be left to pay the cost burden over the asset life.
  - We further query the appropriateness of the AER revenue determination model over time, where NSPs seek regulated rates of return every 5 years and the impact of contingent project applications from proposed ISP projects increasing network revenue recovery caps mid determination period. Project Energy Connect is a current example and many ISP projects will likely take a similar path to the AER.
- **Balancing private vs public sector roles and responsibilities -**
  - While we promote the role of the private sector to deliver the ISP, as above, roles and responsibilities between the private and public sector must be considered with the objective to ultimately limit costs passed through to customers and deliver project efficiently.
  - We note the NSW government is seeking to re-establish its Energy Corporation to deliver REZs and Commonwealth Labour recently announced the Rewiring the Nation Corporation to fund network infrastructure. These entities must be empowered to manage costs not enable cost overruns and time delays to design and construction and held accountable where cost overruns and timetable delays are incurred.
  - Private sector incentives may be misaligned with outcomes. For example, privately owned transmission driven by profit maximisation may not seek lowest cost outcomes for consumers

or may not be concerned about cost overruns that ultimately increase the profit margin without creating additional benefit to consumers.
  - Roles should be considered in the balance. We also acknowledge that state involvement does not necessarily mitigate time or cost increases (e.g. Snowy Hydro) so we recommend the pros and cons of public vs private roles in project design, development and ownership are considered across projects in the ISP.
- **Intergenerational risks of stranded assets -**
  - Cutting electricity costs for consumers continues to be the political mantra to justify transmission investment.
  - We are concerned that building out the entire ISP will lock in stranded network assets and increase the proportion of network charges to electricity bills over time.
  - We have serious concerns about the stranded asset risk of large scale transmission infrastructure, particularly in the context of gold plating consequences and asset write downs.
  - For the young people we represent, this is an important legacy issue for all network infrastructure decisions. The risk of building out the entire capacity of the ISP is that consumers will keep paying for these network assets for 40-50 years; such infrastructure locks in certain solutions and locks out alternatives that may better address the actual problem.
  - We need to ensure mechanisms like the ISP are robust enough to consider non-network solutions to current and future market challenges and adaptable enough to change track over time without locking in solutions that are no longer fit for purpose.

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

   Please see our comments to questions 1 & 2 above.

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

   We do not have views on NERA's modelling assumptions. Please see our comments on COGATI generally below.

- **Reframing congestion risk -**
  - Congestion risk, MLF and basis risk are inevitable risks factored and priced into financial modelling of generators. The greater uncertainty in these risks over time, the greater costs priced into project financials.
  - Generators may be best placed to manage these risks, to the extent such risks are relatively predictable. Historically, these risks have been unpredictable, leading to shifting project economics and limiting bankability or investability of projects. For example, the expected MLF at the time of development, construction and initial generation may be quite different to a couple of years earlier under the financial model, developers may have problems with information asymmetry regarding the timing of other developments and assumptions may be generally unclear on system wide issues.
  - We are concerned that COGATI seeks to address congestion in isolation to other market reforms, issues and barriers. The foundational industry question needs to be 'what is the level of constraint acceptable to generators' and market reform can evolve from there. Models can then forecast for predictable constraint and reduce risks of uncertainty and unexpected curtailment for debt and equity. Financial losses from curtailment could be countered through better economics and incentives for storage technologies, as the economics and dispatch markets evolve over time.

- Unfortunately, when industry is begging for certainty, the introduction of COGATI will add a greater risk dimension (and premium) to the financials for new build generators through locational marginal pricing (**LMPs**) and financial transmission rights (**FTR**). Dynamical loss factors will likely be more unpredictable and variable than existing MLF and it is not clear whether FTRs will give adequate protection to manage such risks.

- **Offset constraint with storage -**
  - Access rights proposed under COGATI are intended to go beyond the current rights to connect by allowing generators to enter into FTR hedges (i.e. seek financial compensation) if they are constrained off and cannot dispatch.
  - In addition to the ISP that builds transmission to alleviate constraints and COGATI that would allow hedging against constraints, we recommend other measures are also enabled to manage generator constraints. One example would be to encourage generators behind a network constraint to install on-site storage to support an alternative revenue stream rather than only lose revenue through constraint e.g. if a generator is anticipated to be constrained 25% of the time, it should build 25% storage capacity to offset the constraint. We note this requires having a commercially attractive revenue stream for storage but may be a more effective mechanism to address intermittency.

5. **What are stakeholder views on the current suite of locational investment signals? The ESB welcomes stakeholder views on alternative solutions to address the need for improved locational signalling for generators.**

   We have several concerns with the proposed COGATI reforms:

- **Lacks clear articulation of the problem -** repeated AEMC materials and stakeholder engagement processes illustrate AEMC is seeking to develop and implement COGATI while not adequately taking into account market feedback and commentary. There is an emphasis on addressing congestion rather than co-ordination (what the "C" stands for in COGATI, not congestion!) and we query whether the instruments proposed will facilitate co-ordination or further complicate the dispatch process.
- **Economic theory removed from market reality -** LMP / FTRs take a purely economic approach to sending signals to generation and infrastructure investment. COGATI has also been introduced and socialised with industry with little consideration of alternative options or reforms to address transmission related issues. Consistent industry feedback from generators and investors are that COGATI may only drive increased investment uncertainty and variable risk that may be hard to price. If LMPs are designed to reflect the actual costs of dispatch in certain locations, we query how this will be predictable enough to inform investment horizons and commercial development decisions for new build generators in order to achieve desired market signals and outcomes.
- **Narrow reform in isolation to wider market reform -** Investment decisions need to be considered in the context of closure of generation (see our comments at MDI B), in the context of shifting demand (see our comments at MDI E) and in response to current transmission reforms. The timing of COGATI needs to also be sequenced with the broader NEM design rather than accommodating NEM design (in respect of transmission at least) to accommodate COGATI.
- **Transactional cost disproportionate to the benefit -** there is a high risk that the transactional cost associated with introducing COGATI (i.e. establishing 12,000 local nodes for LMPs, introducing new IT systems and amending every power purchase agreement, estimated by AEMC to be $5.4m in legal costs alone) may outweigh the perceived benefits. AEMC estimates the transactional cost of implementation will be $110m (which may be conservative).
- **Lack of international lessons learnt -** stakeholders have given feedback that the proposed COGATI reforms are inconsistent with lessons learnt in similar gross wholesale pool markets, in particular New Zealand. There may be a better alternative to COGATI that has not been properly considered yet, however the approach seems to be deemed acceptance of COGATI with stakeholder engagement limited to tweaking the initial proposals.