30th September 2019

Dr Kerry Schott, Chair
Energy Security Board
COAG Energy Council

Lodged electronically: info@esb.org.au

Dear Dr Schott,

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EnergyAustralia response to ESB Post 2025 Market Design, Issues Paper

The Australian energy market is changing at an unprecedented rate due to the current boom in renewable energy investment. Consumers, industry, governments and regulators are working to transition our energy sector to a low-carbon future. This is the future we want our market to drive toward, and we need to consider how lowering carbon can be supported in the market framework.

EnergyAustralia will be a part of that transition.

EnergyAustralia is one of Australia's largest energy companies with around 2.6 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation in the National Electricity Market (NEM).

It is estimated that the transition to a cleaner future will require up to $115 billion of capital investment by 2040.[1] We anticipate, this investment will be made in renewable energy, flexible gas plant, behind the meter rooftop solar and storage with further investment required in the grid.

This investment will need coordination and a framework to guide it. It will need commitment across the entire supply chain, including consumers, industry, regulators and government. Regardless of the market design that is chosen if governments continually change the playing field and intervene, it will not deliver the best outcomes for consumers.

The current Energy Only (EO) market has been shown to deliver investment in the past.

[1] EA analysis based off data from AEMO ISP 2018. This value is determined using the present value of annualised costs of the total investment required to replace retiring generation capacity whilst meeting customer demand across the breadth of scenarios considered, and while excluding committed and advanced projects at the time. We note there are multiple numbers in the public domain on how much the investment will cost, this is just another.

But the key questions with this market are:

- Will it provide the investment signals and returns to attract the capital required to make the transition?
- Will it deliver the right quantity and type of investment needed for the transition?
- Will it deliver the investment to satisfy the Reliability Standard?
- Will the price volatility required to attract investment be allowed to occur or is the level socially unacceptable to consumers and governments?

The Reliability Standard is increasingly seen as a minimum level of reliability for governments and some market stakeholders. What has been seen as a lack of investment in reliability, coupled with the particularly challenging investment environment at present, is reducing faith in markets and driving government intervention. This government intervention in the market, has ranged from asset investment (SA temporary diesel generation, Underwriting New Generation Investments (UNGI), Snowy 2.0, financial support for the NSW-SA interconnector and other transmission upgrades) to proposed legislation (Prohibiting Energy Market Misconduct (Big Stick)) and changes to retail rules (Default Market Offer, Victorian Default Offer). These interventions do nothing to link the Reliability Standard to market economics, but they do place further doubt on whether the market will deliver capacity investment.

EnergyAustralia considers we need to find a socially acceptable, least cost pathway for the market to drive the transition. Continued government intervention will hinder the private sector's ability to deliver and will ultimately lead to higher longer term costs for consumers and costly exposures for government budgets. Given the scale of the investment required ahead we need to get the mechanisms right to have the private sector take risks and make investments for the benefit of consumers.

EA considers alternative market mechanisms to deliver capacity investment should be considered. These designs should focus on providing the investment signals as leading, not lagging signals, that deliver efficient and timely investment without socially undesirable levels of price volatility and reliability risks. We also need to adjust expectations of what the Reliability Standard means, or, find a mechanism to link the socially desirable levels of reliability with the economics of a market. When considering alternative market designs, a central question is how risk is allocated. Models to reform the energy market sit along a spectrum of risk sharing. Models with more centralised planning potentially smooth price outcomes, but place the risk of poor investment decisions on consumers/taxpayers. Our current energy-only model relies on price volatility and places the risk of poor investment decisions on generators.

The decline in synchronous generators and entry of Variable Renewable Energy generators is placing pressure on system security. This is likely to continue, with increased prevalence of AEMO interventions, as we progress through the transition. Currently the EO market does not sufficiently value system security services. **We need to better understand system security services so that the market can invest in them**. Once system security services are defined, AEMO needs to transparently communicate how much it needs, where and when. This communication needs to be provided in advance, potentially 2 to 5 years out, so that sufficient investment can occur.

This will provide a value for system security services and send a long-term signal for the private sector to invest and should enable the lowest cost options for acquiring system security services.

As an industry we need to keep our eye on the long-term goal and lay out a plan to achieve it. This plan needs to be practical, targeted and reflect the right mix of technical/economic purity and ease of use. This will help create the certainty and confidence that is needed for large investments. Based off this long-term plan, we should develop stepping stones that will help inform responses to current problems. Current regulatory changes, such as Co-ordination of Generation and Transmission Investment (COGATI), and rule changes on intervention pricing, for example, should be informed by the long-term goal.

The remainder of this submission follows the Energy Security Board (ESB)'s analytical framework and addresses the questions as structured in the Issues Paper.

If you would like to discuss this submission, please contact Sarah Ogilvie on 03 8628 1805, sarah.ogilvie@energyaustralia.com.au.

Regards

Ross Edwards
Markets Executive

1. Analytical framework

The ESB has presented a comprehensive and accurate description of the key challenges in our energy sector. EnergyAustralia supports the ESB's analytical scope being framed by the five key categories.

The electricity market exists because consumers value electricity. The market must focus on the needs of consumers and respond to those needs. EnergyAustralia considers that the **National Electricity Objective, National Gas Objective, and National Energy Retail Objective encompass the necessary principles** to ensure the market responds to consumer preferences. These Objectives focus on productive, allocative and dynamic efficiency to provide the long-term interests of consumers, both now and into the future.

EnergyAustralia considers additional principles of importance are:

- driving low-carbon outcomes now and for future generations,
- consumer empowerment, and being able to reflect different consumer preferences
- transparency,
- practicality – it needs to be 'doable' and reflective of the Australian context, and
- simplicity of design (we recommend transparency and simplicity be separate for consideration – they are often very different things).

It's also worth calling out that productive and dynamic efficiency would ensure that the market equally rewards current and future investment for providing the same service, and there is neutrality in incentives between brand new investments and maintaining existing plant.

Alternative market designs, which seek to address the challenges of the existing and future market, should be assessed against these principles.

EnergyAustralia supports the ESB using the ISP as a scenario basis. To use it for this purpose, the ESB may wish to consider expanding the consideration beyond spot market and wholesale perspectives and consider an even more deeply integrated outlook that takes into account end use tariffs and distribution network expenditure and therefore broader end use customer impacts and the total costs anticipated.

Any new market design absolutely must have a cost benefit analysis applied to it to ensure we are changing the market for the good of the customer. If the costs outweigh the benefits, we should not proceed with the change. The costs and benefits need to be quantified and tangible. We suggest the AER undertake this cost benefit analysis and that it is informed by a public consultation process. The ESB's market design should also consider transitional arrangements, which should be clear, tangible and timely.

ESB's specific questions:

What scenarios and shocks should be used? How should these be used to test market design? *Is the assessment framework appropriate to evaluate the effectiveness of future market designs? What else should be considered for inclusion in the assessment framework?*

We consider the following scenarios and shocks/structural changes should be used in analysis and modelling:

- closure of dispatchable synchronous plant that is displaced by new interconnectors and Variable Renewable Energy (VRE), and how this impacts:
    - system security
    - the availability of financial contracts, which are used to smooth prices for customers and signal expectations of future electricity price,
    - spot and futures prices,
- a loss of financial contract intermediaries,
- the impact of large load closures on spot and futures prices,
- an expeditated declining cost curve for new technologies,
- the responsiveness of customer demand to declining prices,
- a variety of weather conditions, including the correlation of wind and solar events, water, wind and sun droughts,
- fuel adequacy insufficiency,
- more rapid or slower uptake of new consumer technologies such as Electric Vehicles (EV) and distributed energy resources (DER), and
- development risks and lead times for new generation and fuel (coal and gas) investments.

Is the assessment framework appropriate to evaluate the effectiveness of future market designs? What else should be considered for inclusion in the assessment framework?

See comments above regarding assessment principles.

Individual components of a market design should be tested against the principles. Ultimately the market design will be a combination of individual components, and so the entire design as a 'package' should also be tested against the principles.

How can market and economic modelling best be used to evaluate individual components of market design or the end-to-end market design?

EnergyAustralia is very happy to support the ESB with determining its modelling inputs and assumptions.

Modelling of market outcomes is best done over a range of time periods, and not at a static point in time. This will help to understand year-on-year price volatility and how that is translated into end user prices.

The modelling should consider the long-term financial commitments made to invest in the full supply chain. For example, gas needs to be produced from a gas field (future sources of gas could include Northern Australia, Longford, or LNG imports), transported and stored (Iona or LNG ship if it is imported LNG) and then transported to the generator, on demand via pipelines. Each piece of infrastructure needs a payback period of 10 years or more to recover its investment. Black coal similarly has large upfront infrastructure investments. Similarly, renewable investments have the risk of becoming stranded if the market is not delivering the expected value post any contract period. These upfront infrastructure costs are included in business cases and need to be included in market price signals.

2. Investment signals to ensure reliability

The NEM is emerging from a period of structural oversupply, that dates back to when governments controlled generation, transmission, distribution and retail. This is coinciding with a time when new technologies are emerging to provide low-carbon alternatives to traditional coal-fired generation.

Since disaggregation and privatisation, the key driver for new entrant plant has been peak load growth driven by the uptake of air-conditioning load. This has driven investment in additional peaking generation.

Most of the new peaking generation has been:

- built by vertically integrated gentailers (Somerton and Hallet, AGL; Mortlake and Darling Downs, Origin; Tallawarra, EnergyAustralia; SA Diesel peakers, Lumo)

- built by generators for fuel diversification (Valley Power and Colongra, Snowy Hydro)
- Underwritten by retailers via long-term contracts (Uranquity and Braemers, Origin)

The only new coal generation commissioned in the last fifteen years has been built by the Queensland government. There has been substantial investment in renewables, driven by federal and state policy targets.

Today the driver for new entrant growth is not the more traditional response to increasing consumer demand, rather it is a mix of:

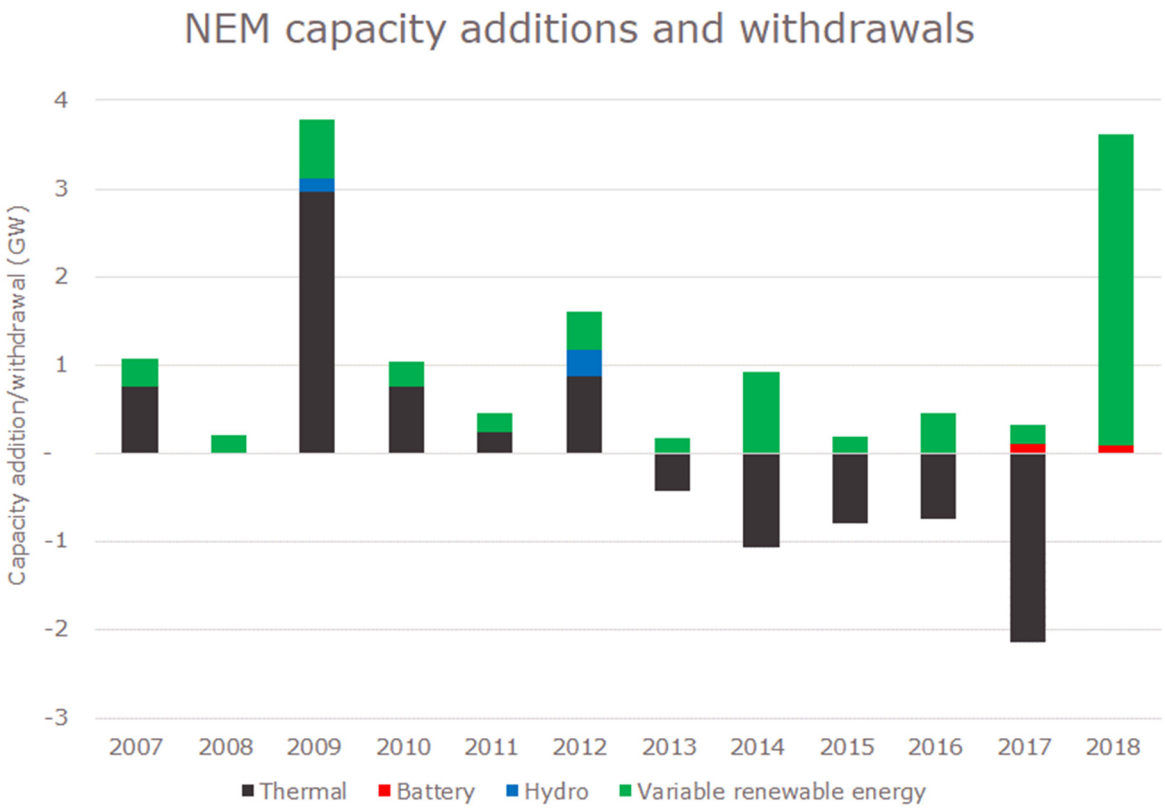
- Looming retirement of existing coal generation due to the end of technical life,
- Society's drive for renewables to replace traditional coal generation, and
- The need for additional flexible capacity and storage to complement renewables.

Investment responding to these circumstances creates a different set of challenges, especially regarding the certainty on timing of expected retirements.

In the EO market a key visible investment signal for new and firm dispatchable capacity are the $300/MWh strike cap contracts. Retailers and large users use caps to cover the risk of financial exposure to high price volatility in the spot market. Caps are a purely financial product and are not subject to the NER. The premium for the contract reflects the markets view on the level of price volatility in the future period.

Retailers and large loads pay a premium to purchase a cap product. This premium reflects the demand for products to mitigate the risk of high prices. Once this price reaches a certain threshold – depending on your risk appetite and cost of capital etc – it becomes more economic to build generation.

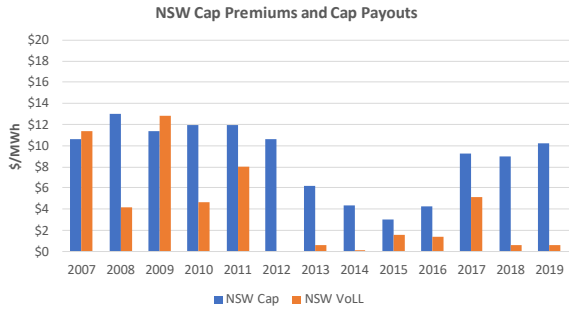
As the chart below highlights, while there was substantial investment in new dispatchable synchronous generation up to 2012, this activity has now ceased. The only additional new entrants since then have been non-market emergency diesel peakers, approx. 200 MW of heavily subsidised lithium ion batteries and variable renewable energy (wind and solar). The recent boom in renewables has been driven by a separate, non-market signal through the RET, VRET and QRET etc.

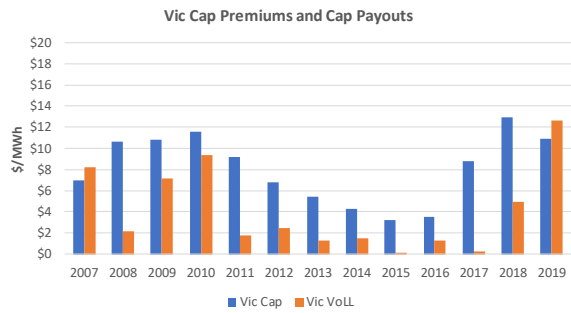


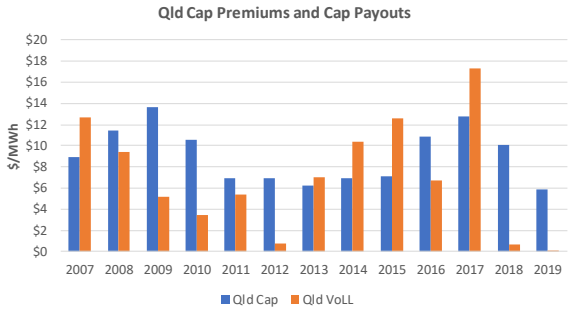
Source: EA analysis 2019

The majority of greenfield power stations would require a sustained cap premium between $12 - $15/MWh. To justify an investment the cap premium and implied level of price volatility needs to be maintained, on average, over the investment timespan. To put this in perspective, a new entrant investor requires the price volatility outcomes for the latest 2019 Victorian summer to be repeated every year for 25 years.

However, the EO market recently has displayed new entrant cap prices, but are often followed by subdued periods, with less potential value from prices higher than $300. The charts below highlights the current year on year volatility of price caps.







Source: EA analysis. Cap premiums based on the volume weighted ASX trading cap premiums in the year ahead of the relevant period.

The current year on year volatile cap price makes it hard to get business cases up due to the downside risk. This increases the risk premiums and project Weighted Average Cost of Capital (WACC). From an investors perspective you need a tight supply/demand balance to drive the high prices to allow caps to provide the new entrant signal, however this increasingly brings with it the risk of political interventions.

This price signal needs continuity to reflect the long-term investment requirements. Additional risks which are evident in our market today include:

- Uncertain demand and supply side factors
- Declining cost curves, and
- Government subsided investment.

These force the risk premium to be higher, and/or signalled in the market for longer.

An additional risk, worth noting, is one that relates to storage. Not only is the value of the output uncertain, the value of the input is too – so the uncertainty is amplified. This is at a time when AEMO predict we need investment in storage equivalent to eight Snowy 2.0 capacity upgrades. This may result in other dispatchable technologies being built (ie. OCGT), in the short term rather than storage. Storage should play an important role to complement renewable energy, however with an energy only market it is challenging to secure revenues for the services it provides.

The ESB could consider requesting modelling undertaken by independent infrastructure investment financiers and ask the question; how high does the price cap premium need to be and for how long to encourage the quantity of investment that we consider is needed for the NEM's future?

2.1 Market Design implications

The current Reliability Standard requires at least 99.998 per cent of forecast customer demand to be met each year. The standard was last reviewed in 2018 by the independent Reliability Panel and is informed by the value customers place on a reliable supply of power. EnergyAustralia strongly supports the Reliability Standard and the oversight that the Reliability Panel has.

To help deliver investment to meet this standard, the market is guided by AEMO's regular short, medium and longer term forecasts (including the Electricity Statement of Opportunities and Projected Assessments of System Adequacy process). However, there is no explicit link, or leading price signal from the Reliability Standard to directly drive the economics of investment in the EO market. The economics of investment sit with the private returns reflected in the real time supply of energy.

The Reliability Standard is increasingly seen as a minimum level of reliability for governments and some market stakeholders. What has been seen as a lack of investment in reliability, coupled with the particularly challenging investment environment at present, is reducing faith in markets and driving government intervention. This government intervention in the market, has ranged from asset investment (SA temporary diesel generation, Underwriting New Generation Investments (UNGI), Snowy 2.0, financial support for the NSW-SA interconnector and other transmission upgrades) to proposed legislation (Prohibiting Energy Market Misconduct (Big Stick)) and changes to retail rules (Default Market Offer, Victorian Default Offer). These interventions do nothing to link the Reliability Standard to market economics, but they do place further doubt on whether the market will deliver capacity investment.

EnergyAustralia considers we need to find a socially acceptable, least cost pathway for the market to drive the transition. Continued government intervention will hinder the private sector's ability to deliver and will ultimately lead to higher longer terms costs for consumers and costly exposures for government budgets. Given the scale of the investment required ahead we need to get the mechanisms right to have the private sector take risks and make investments for the benefit of consumers.

EA considers alternative market mechanisms to deliver capacity investment should be considered. These designs should focus on providing the investment signals as leading, not lagging signals, that deliver efficient and timely investment without socially undesirable levels of price volatility and reliability risks. We also need to adjust expectations of what the Reliability Standard means, or, find a mechanism to link the socially desirable levels of reliability with the economics of a market.

When considering alternative market designs, a central question is how risk is allocated. Currently the energy supply chain sees retailers and generators as requiring private returns to support investment, whereas monopoly networks rely on more generalised market benefits to support investment. This may be appropriate, but it is worth considering how this will impact price levels and volatility. Models to reform the energy market sit along a spectrum of risk sharing. Models with more centralised planning potentially smooth price outcomes, but place the risk of poor investment decisions on consumers/taxpayers. Our current energy-only model relies on price volatility and places the risk of poor investment decisions on generators.

Additionally, reliability should also be considered through the customers perspective. Around 96 per cent of supply interruptions to customers are due to problems in the network, for example when a pole is knocked down in a storm, 4 per cent of supply interruptions to customers are caused by security events, and 0.3 per cent of supply interruptions to customers are caused by a lack of supply capacity to meet consumer demand.[2] Reliability standards, planning levels etc should be set across the energy supply chain (generation, transmission and distribution) to maximise consumer benefit and value from reliability. There is questionable consumer value in strengthening the Reliability Standard for generation, when consumers largely face 'reliability' issues from network constraints.

3. System security and resilience

The exiting of synchronous generators that have traditionally been relied upon to provide essential system security services is placing considerable pressure on the current market framework to deliver security of the power system.

As a result AEMO is increasingly intervening in the market to ensure system security, in particular in South Australia. As the generation and demand mix changes, for example due to increasing penetration of roof top and utility scale solar, we expect these issues to become more common in other regions in the not too distant future.

Recent rule changes to develop system strength and rate of change of frequency framework appear to have not been successful or flexible enough at managing the increasing needs of system security. This has led to AEMO becoming reliant on direction and interventions to maintain system security.

EA sees both the immediate and longer-term requirements for system security as paramount. And we are keen to work closely with both the ESB and AEMC to progress improvements to these issues immediately.

3.1 Market Implications

Currently the EO market does not sufficiently value system security services. **We need to better understand system security services so that the market can invest in them**. Once system security services are defined, AEMO needs to transparently communicate how much it needs, where and when. This communication needs to be provided in advance, potentially 2 to 5 years out, so that sufficient investment can occur. This will provide a value for system security services and send a long-term signal for the private sector to invest, and should enable the lowest cost options for acquiring system security services.

EnergyAustralia, supports where possible, competitive market based arrangements (which can follow any number of designs) to procure these security services and to this end, we do not support AEMO's current rule change proposal which mandates primary frequency control from all generators. Incentives for delivery of this from willing

[2] AEMC website; https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability

suppliers are especially critical for the NEM as traditional providers of frequency services cannot be relied on in the long-term as the industry transitions.

We also need to think in a combination of generation and network – not just rely on networks (TNSPs) to deliver security outcomes. The investment framework for this currently sits with the TNSP regulatory framework, and this may need consideration to ensure security services are provided at lowest cost to customers.

We note that there are ample examples of other international markets where a suite of security services is procured through market based measures.

4. Driving innovation to benefit the consumer and integration of Distribution Energy Resources (DER) into the electricity market

The ESB Issues Paper discusses driving consumer outcomes and the integration of DER into the electricity market separately. However, we have combined our comments on these issues in this submission.

We strongly agree with the ESB statement that "the overall market design and regulatory settings need to ensure these new service offerings emerge in a way that ensures security and reliability are maintained through the transition and that customers have the protections they need".[3]

We are moving away from the long-established business model and market structure which has been based on the mono-directional flow of energy, to something that is more genuinely a system, with customers facing more choices about their behaviour to consume, produce and share energy within communities.

While there are many complex issues associated with DER integration, the two main challenges appear to be:

- Better promoting allocative efficiency – ensuring costs and benefits from DER are appropriately paid/received by the beneficiaries. This will ensure existing resources are utilised in their optimal way as well as ensuring the system evolves in a way that provides the greatest long-term value to consumers.
- Addressing equity and distributive issues – some customers are willing and able to commit to the upfront costs of technologies and can benefit from load shifting or demand reductions. Other customers may be unable to engage in this process and could miss out on benefits or even face higher costs. Some customers may also choose to disengage in the energy market or avoid technologies and more complex energy services. Managing these different preferences can be done within market design parameters or externally through government policy, and will affect the total benefits that can be captured through effective DER integration

4.1 Market Design Implications

[3] Energy Security Board, Post 2025 Market Design, Issues Paper, September 2019, page 14.

To help face these challenges we need market and regulatory settings that promote transparency and considered data sharing. Consumers, networks, third party service providers and AEMO will need visibility of a range of data including export and input data, prices (wholesale and retail) and voltage impacts. The role and sharing of customer data will be central and requires proper management and consumer protections. Consumer Data Right will be an important enabler.

DER and related technologies will enable the rise of semi-regulated entities and services in the supply chain. Consumers will need appropriate protections around this. Removing or not imposing consumer protections to promote investment in a technology or DER related activity need to be rigorously tested, and limited.

Distributional impacts should be considered broadly, and not focus on one group of consumers. Trade-offs and transitional issues need to be discussed in a fulsome way. We recommend the ESB give some consideration to the customer centric nature of changes and the role of gaining appropriate social licence. DER users both have rights and responsibilities in the system – their behaviour can both positively and negatively affect other users - and they need to be aware of this when having input into market redesign and reforms. We note that a large number of user representatives are coordinating the development of DER reform design principles under the umbrella of the Distributed Energy Integration Program, and the ESB should explore the outcomes of this initiative.

Current opportunities to consider the efficiencies and distributive impacts of DER include network tariff reforms and related issues around network access. Appropriately designed pricing structures and access rights will, for example, address the rising concern of solar PV customers benefiting from cross-subsidies and adding to total network costs via the building out of export constraints, or being refused the ability to export. Issues tangential to this are the role of government subsidies (including those contemplated for electric vehicles) and regulated Feed-in Tariffs (FiTs) that are intended to reflect the social cost of carbon as well as the marginal value of generation (particularly solar PV) in spot markets that are becoming increasingly more volatile. We support investigations into these issues. The existing relationships between networks, retailers and customers should also be carefully considered. For example, retailers have a role in minimising all aspects of the final customer bill and better visibility of the customer's load and export characteristics (and so should play a central role in pricing reform). Whereas networks will have an important role to play in developing technology platforms that are neutral to different forms of energy service provision, including by aggregators and other third parties.

5. Integrating Variable Renewable Energy (VRE) into the power system

AEMO's Renewable Integration Study, which is looking at power system limits of penetration of particular technologies is valuable work, not just in terms of identifying the limits but in setting the groundwork for industry consultation on how to extend these limits. Such limits can reasonably be extended, if desired, through a combination of changes to AEMO's operational tools, by considering the incentives inherent in the market design and policy changes and network operational tools. We consider AEMO's Renewable Integration Study should inform the ISP, and help to determine future system security service needs.

An ISP, reflecting power system limitations, consistent assumptions, consideration of network and non-network solutions, and thorough and transparent cost/benefit analysis may help to guide transmission investment. But it is still a guide and while it forms a compelling case for transmission investment, it does not direct investment. This is left to the market to decide. For the market to operate efficiently it needs transparency in transmission and generation investment decisions. This can create clear pricing signals to maximise consumer outcomes and encourage efficient investment decisions from the transmission and generation businesses.

However, the difficulty in coordinating generation and transmission investment lies not only in the inherent lumpy and timing mismatch of investment, but also in the risk framework for the two parts of the energy supply chain.

Increased reliance on interconnection as a source of capacity in a renewable dominated market also increases risk regarding the underlying correlation of renewable generation and coincidence of demand. While we are encouraged that AEMO is using a multi-year reference period for the next ISP to explore the implications of both hydrological and wind droughts, we believe that society may not treat low probability, high impact 'black swan' outlier weather or climatic events as an acceptable reason for supply failures.

5.1 Market Implications

Any choice of market design of the NEM is going to need to consider how transmission and generation investment will interact and who will bear the risks of poor investment by either party. The AEMC is facing this challenge through its COGATI review. Throughout this review we consider some fundamental principles are that:

- any new nodal pricing or transmission access regime has benefits that outweigh the costs,
- the reforms have the purpose of providing price signals for future investments to maximise consumer benefits by prioritising the trade-off between building where the 'input' resource is vs building near existing and uncongested transmission lines.
- It is a price signal/incentive approach, not a penalty approach. That is, do not penalise existing generators that did not have the price signal in existence before investment approvals.

ESB Questions:

Have we identified all of the potential challenges and risks to the current market? In not, what would you add?

EA's comments throughout the submission answer this question.

Which of these risks and challenges will be most material when considering future market designs and why?

From EAs perspective we see the challenges relating to utility scale investment to support reliability and system security services as the most material challenge. Hopefully our discussion in section 3 and 4 of this submission explains our position on these challenges.

Which (if any) overseas electricity markets offer useful examples of how to, or how not to, respond to the challenges outlined in this paper?

The ESB makes some useful comparisons throughout the Issues Paper. EA's two specific comments here are:

- We agree with the ESB, that the NEM has number of unique features, and we are an island with no inter-country linkages. There are real risks that we pick up the models of other countries without properly understanding how Australia is different.

- We strongly encourage the ESB, AEMO and the AEMC to focus on how other markets have defined and found value in system security services. These definitions need to advance so that 'products' which the private sector can invest in and supply are available for the safe and reliable running of our power system. If this doesn't occur system security services are likely to be procured at a much higher cost to the consumer. EA understand Ireland has a well-defined system services market that provides leading price signals and may provide useful examples.