Enel Green Power Australia Pty Ltd
Level 23.07, One International Towers
100 Barangaroo Avenue
Sydney NSW 2000

Dr Kerry Schott AO
Independent Chair
Energy Security Board

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Lodged by email: info@esb.org.au

Dear Dr Schott,

Re: POST 2025 MARKET DESIGN – CONSULTATION PAPER

Enel Green Power (EGP) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC's) Consultation Paper.

Founded in 2008, and part of Enel Group, EGP builds and operates large scale renewable generation capacity in energy markets around the world. EGP operates in 28 countries on 5 continents with a managed capacity of over 46 GW and over 1,200 plants. EGP is the largest privately owned renewable energy company in the world, generating approximately 100 TWh of renewable electricity from hydro, solar, wind and geothermal resources every year.

We agree with the Energy Security Board that a fundamental energy transformation is taking place. The power system is changing:

- Historically dominated by comparatively few large and centrally located generators , the power system is now transforming to one with many smaller generators located at the fringes of the grid;
- The transmission network previously had plentiful spare transmission capacity but now generators are increasingly competing for access to scarce transmission capacity;
- The power system was previously dominated by dispatchable generation capacity with high marginal costs, which is increasingly being replaced with non-dispatchable generation with zero marginal cost;
- The energy market is becoming more decentralised with every increasing volume of residential solar systems and other distributed energy resources (DER) being installed in the distribution system and behind the meter.

All of this is creating concerns at the policy level about whether the existing energy only market design can manage three key issues (or groups of issues):

- ***Congestion***: caused by increasing volumes of smaller generators competing for access to scarce transmission capacity in fringe of grid areas;
- ***Reliabilit****y*: whether this can be assured in a future power system dominated by zero marginal cost variable renewable energy (VRE);

- ***System Security***: how to address lower inertia and weakening system strength as emissions intensive synchronous generators exit the market and increasing quantities of inverter based generation replace them.

The Energy Security Board's Post 2025 Market reform program is exploring 7 key market design initiatives largely focused on managing these issues.

We focus attention in this submission on the consultation issues of most relevance to EGP's business. Our views are briefly summarised below:

- ***Resource Adequacy Mechanisms***: we do not consider a sufficiently strong case has been made for the implementation of a new resource adequacy mechanism. We consider the scarcity price signals provided by the existing energy only design are sufficient to promote the investment needed to support long term reliability, and is likely to best encourage the flexible and fast responsive resources required to support a future power system dominated by renewables (particularly when supported by an LMP and FTR framework). The existing regulatory backstop mechanisms the RERT and existing RRO should provide government with sufficient reassurance that reliability of supply will be maintained if the market fails.
- ***Essential System Services:*** We consider that in an environment of decreasing inertia the development of a Fast Frequency Response (FFR) market will add real value to the NEM and strengthen signals for investment in the fast responsive technologies required to support a high a power system dominated by renewables. It would also represent a relatively incremental change to the existing market arrangements. On the other hand, we consider that future inertia and system strength requirements are likely to be best managed through structured procurement arrangements (coordinated by AEMO and NSPs) rather than markets. This is due to the complexity of defining the precise scope and quantity needed of these services and the lumpiness in their provision.
- ***Short term forward market:*** While we agree with the concept of a unit commitment service (UCS) to provide AEMO with greater confidence that resources will be available when they need them, we do not foresee a clear need for a voluntary short term forward market (SFM). It is likely such a market will see low liquidity given the availability of existing financial market hedging tools. Voluntary SFMs appear to be more suited to EU energy markets characterised by bilateral contracting, and where SFMs provide the key mechanism for creating a reference price for financial contracting.
- ***Renewable Energy Zones:*** We strongly support the work the ESB is doing on developing a new framework for REZs, particularly consideration of innovative new business models for encouraging private investment in network infrastructure. As demonstrated by the escalating costs of Project Energy Connect, network assets and components are becoming increasingly expensive as demand for them increases around the world to support the energy transition. Therefore, finding sources for transmission funding other than consumers will be intergral to supporting the efficient and timely development of the grid.
- ***Transmission Access and Pricing reform*** While the AEMC's proposed reforms for pricing and access are complex, we nevertheless broadly support them. In light of the sheer scale of new entry anticipated over the next two decades (according to AEMO some 41,000 MW of VRE generation capacity), an FTR and LMP framework is the only way we can think of for allowing participants to satisfactorily manage increasing levels of congestion risk. However, we consider that a key missing link in the framework is the opportunity for investors in transmission or connection assets to receive free FTRs for the new grid capacity they create. This would provide a strong additional incentive for private investment in new transmission capacity.

Our responses to the specific questions raised in the ESB's consultation paper have been set out in the Appendix.

Please feel free to contact Con Van Kemenade, Head of Regulatory Affairs, on 0439399943 to discuss anything we have raised in this submission.

Yours faithfully,

Javier Blanco
Country Manager
Enel Green Power Australia

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Level 23.07, One International Towers
100 Barangaroo Avenue
Sydney NSW 2000

Appendix

Responses to specific questions raised in the Consultation Paper

Resource Adequacy Mechanisms		
1	Do you have views on whether the current resource adequacy mechanisms within the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition?	We believe the existing signals provided by the energy only design are sufficient to promote the investment needed to support long term reliability, particularly as we move to 5 minute settlement and a wholesale demand response mechanism. We consider the energy only design can adapt to more volatile prices cause by a greater penetration of VRE generation, and indeed it is a fundamental characteristic of the energy only design to be able to do so. Prices will rise in peak times to incentivise investment in the types of generation that can complement renewables to meet demand, such as open cycle gas turbines, battery storage or demand response. Price volatility is not inefficient in and of itself, it is a core part of the energy only design and underpins a liquid contract market. Financial markets provide a range of different contract types such as swaps, caps, PPAs and futures, which collectively drive future investment in the mix of different technologies required to support a reliable power system. Central to achieving reliability under an energy only market design however is to have a sufficiently high market price cap (MPC) in place, so that it can adequately signal scarcity to promote investment in the right types of capacity. Australia has the highest MPC ($15000 MWh) in the world, which is more than adequate to the task for supporting investment in dispatchable capacity to ensure reliable outcomes.[1] There is also an independent, evidence-based framework for reviewing and amending the settings. The Reliability Panel has a role to assess and review the MPC and other settings as required for consistency with the reliable operation of the market. We would prefer to see this process used to strengthen incentives for

[1] EY Reliability Standards and Settings Review 2018 – Modelling Report For the Reliability Panel, p 7

		investment in dispatchable capacity where needed, rather than a significant redesign of the market. It is worth noting that the reliability standard has not been breached in the NEM to date. Further, the latest AEMO ESOO predicts no breach of the reliability standard is expected in the reports 10 year forecast horizon.[2] While we acknowledge that maintaining reliability has become more challenging in recent times with the RERT being triggered more frequently and an increase in occasional load shedding, this must be placed in context of having three of the hottest summers on record over the past 5 years and an increasing incidence of outages of thermal generators in the market at times when they are most needed.[3] It is not obvious to us that any other type of framework would have handled the extreme weather conditions more effectively. While the NEM's backstop mechanism, the Reliability and Emergency Reserve Trader (RERT), was called upon both in 2019 and 2018 (the first in the last decade) we also note the cost of doing so was in fact very low relative to overall market revenues ($34 million in 2019).[4] It is therefore not clear to us that significant redesign of the energy only market for reliability purposes is needed at the present time. The strength of the NEM is that it relies on market signals and the decentralised interactions of retailers and generators to determine the right amount capacity to invest in to meet demand growth. Market participants are likely be better at working out the future consumption requirements of their customers (because their profits depend on it) compared to a centralised planner, which inevitably will have strong incentives to ensure too much capacity is procured.[5] Moving to any kind of separate payment for capacity or forced contracting mechanism will at some level distort the price signals of the wholesale market, because the demand curve will be created artificially, rather than through the decentralised interactions of retailers and generators. We consider the current energy only market design with the RERT and RRO as a backstop (which we like less, but can live with) provide a reasonable balance between letting markets to drive efficient outcomes and giving the governments reassurance that the lights will stay on should the market happen to fail. The RERT has to date been a highly cost effective backstop mechanism which has been called upon infrequently since the start of the NEM.
2	Do you have views on whether the short-term signals provided by an operating reserve	An operating reserves mechanism is the most preferable of the capacity options considered in the consultation paper, as it is most complementary with the energy only market design

[2] AEMO ESOO 2020, p 7

	mechanism or market would provide adequate incentives to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What impact could an operating reserve have on financial markets? What are the benefits of this approach? What are the costs and risks?	However, it is not clear to us that an operating reserve mechanism is needed for Australia. As noted, the MPC is already set at a level that can provide a sharp scarcity signal to promote dispatchable capacity and can be adjusted through an independent review mechanism if needed. In our view an operating reserve mechanism, and similar scarcity mechanisms, only have real value in markets where generator offers have been artificially capped below the levels they would need to recover their costs, such as the majority of US markets. An operating reserves mechanism is likely to add little over existing arrangements in our view. It will also add an additional layer of complexity to the NEMs energy only design to which participants will need to adapt and incorporate into their risk management arrangements. For example, it will require administratively determined demand curve for reserves (with prices set by AEMO rather than the interactions of retailers and generators) and a new price cap will need to be established based on some measure of lost load probability (LOLP) and the value of lost load (VOLL). This will likely have considerable impacts on the financial and contract markets and structure of existing contracts.
3	Do you have views on whether the signals provided by an expanded RRO based on financial contracts or a decentralised capacity market would provide the type of incentives participants need to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What are the benefits of this approach? What are the costs and risks?	As noted above, we consider the existing NEM design, and its settings (in particular the MPC) are sufficient to provide the signals required to promote reliability. An expanded RRO mechanism or decentralised capacity market operate through centralised planning of future generation capacity, which we consider creates a significant risk of over procurement. As noted above, experience from countries where capacity is separately priced on the basis of centralised planning increases costs to consumers.
4	Do you have views on how an operating reserve mechanism and/or expanded RRO would impact the need for and use of RERT and the interim reliability reserve if they were introduced into the NEM? What adjustments to the RERT and/or interim reliability reserve may need to be made so that they are	The implementation of an expanded RRO (essentially an mandatory procurement arrangement for capacity) would remove the need for RERT altogether (it would never be called on) so there would be little point in keeping it in place. In our view, as we argue above, an operating reserves mechanism would not offer much more in terms of scarcity pricing signals compared to the existing wholesale market. The RERT would therefore still be required as a backstop to deal with potential market failure that arises over a longer time frame (e.g. a lack of investment in new generation capacity due to policy uncertainty or excessive government intervention).

[3] AEMC Reliability Panel, Final Report, "2019 Annual Market Performance Review", p iv
[4] Ibid, p 75
[5] For a good discussion on the problems with capacity markets in the US see: Grid Strategies LLC, "Too much of the Wrong Thing, The need for capacity market replacement or reform", November 2019

	complementary and not contradictory or duplicative?	
5	Do you have views on how RAMs (current or future) can better be integrated into broader jurisdictional policy priorities and programs? Should jurisdictions reflect broader policy priorities through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve?	We acknowledge governments are right to be concerned with reliability, given the consequences of cascading outages and blackouts on the voting public. A complete reliance on markets is likely to be imprudent from a government accountability perspective. Excessive regulation or intervention in the energy market should be avoided however. While governments should set the reliability standard, it should be left to the market and the national electricity rules (NER) that support it to achieve that standard. We consider the current balance is about right, with the RERT and RRO as backstop. We note that the RRO can be triggered by governments if they become concerned that the NEM is insufficiently forthcoming with timely investment in new generation investment. We consider the RRO is likely to work better as a backstop mechanism rather than as a complete and ongoing replacement of the existing market arrangements.
1. Essential System Services		
1	What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating reserve procurement for resource adequacy? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment needed for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?	EGP considers the key market design challenges brought about by the energy transition are congestion and system security, rather than reliability. We strongly support the ESB's attention on strengthening frameworks for valuing essential system services (system strength, inertia and frequency response). It is not clear to us however that a 'spinning reserve' market is needed given the 8 FCAS markets that already exist to provide reserves in multiple time frames to balance supply and demand on the network. These markets would benefit however form an additional FFR FCAS service to properly value almost the instantaneous (in milliseconds) response that technologies such as batteries can provide to address frequency drops. For system strength and inertia, given the required quantities of these are much harder to define and are lumpy in delivery, we agree these are more suitably procured through longer term 'structured procurement mechanisms', as the ESB puts it, coordinated through either AEMO or the TNSPs with costs recovered on a beneficiary pays basis (we agree identifying specific causers is difficult). Further, the structured requirement for inertia is more adaptable to a developing market in FFR, with TNSPs reducing their contractual requirements as the FFR market develops.
2	What are your views about developing FFR with FCAS and developing a demand curve for frequency response? Will such a mechanism help manage greater system uncertainty more efficiently than current	We consider that in an environment of decreasing inertia the development of a FFR market will add real value to the NEM and strengthen signals for investment in the flexible technologies required to support a high renewable penetration. It would also represent a more incremental change that could be readily incorporated into the existing FCAS market framework (as an additional FCAS MW requirement). Implementing a sloped demand curve approach to

	arrangements? What additional mechanisms might be needed to foster investment for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?	frequency services which expresses a willingness to pay for increasing volumes of an essential service) to frequency services could have merit, as it could provide more predictable price signals for FCAS providers, and thus stronger incentives for investment. Under the current vertical demand curve approach for ancillary services there are wild price swings.
3	What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, and what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?	As we note above, we support a structured procurement approach, coordinated between AEMO and the TNSPs to be primarily responsible for supporting system strength and inertia. The framework outlined by the AEMC in its Final report of its investigation of system strength frameworks, which combines centralised planning with new technical standards for generators provides a reasonable compromise for procurement of system strength in the NEM. The planning components of the model could also be applied to procurement of inertia, to ensure a consistent approach. Further, a market for inertia is likely to be very thin, since few resources are able to provide it, particularly compared to FCAS where the potential supply is much greater and so the FCAS market is likely to be more competitive. Finally, a market for inertia could result in a reduced need for FCAS. FCAS provides an important value stream for both batteries and demand response, both of which are seen as critical for grid stability and security. The AEMC has previously recognised this, stating. We do not support PSSAS mechanism. Not all technologies are able to provide a combination of services, which would therefore limit competition in provision of a bundled service. Setting up discrete arrangements for the purchase of each service independently is likely to lead to lower overall cost of provision of these services. Such an approach would not limit a particular technology from participating in more than one market or procurement arrangements.
4	Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?	The scale of the energy transition is unprecedented, in terms of the volume of new connections, changing technologies and business models and grid impacts. Providing AEMO and the TNSPs with as much flexibility as possible to help address these challenges is important. This may range from new funding and cost allocation models for transmission investment (Transgrid model) to co-funding models for sharable PSCAD models, to testing innovative new technologies or business models to support wholesale markets. Grid scale battery storage provides an example for why this is important. It has great potential to contribute to decarbonisation by storing renewable energy and supporting grid security through frequency support, but its deployment at scale will require continuing innovation in business models and changes to market frameworks for it to succeed. Under existing market rules grid scale storage is unable to capture the multiple revenue streams it needs to effectively compete with higher emissions gas fired peaking generation. Without a comprehensive

		approach that factors in business models and regulation, its commercial deployment will remain limited. We note in this regard that the AEMC has recently introduced Regulatory Sandbox arrangements, which will allow energy market participants to run trials for innovative concepts at a smaller scale, on a time-limited basis and with key regulatory obligations relaxed. The framework would provide the opportunity for participants to work with regulators and governments to test new technologies and assess how they interact with the wholesale market and networks.
2. Scheduling and Ahead Mechanisms		
1	The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?	EGP sees value in the implementation of a UCS. However, we do not see value in the establishment of a voluntary ahead market. We consider a voluntary ahead market will lack liquidity as existing financial markets provide the required tools participants need to hedge their risks. We understand voluntary ahead mechanisms are only used in European markets which have a fundamentally different market design to our own and where such arrangements would make more sense. In particular EU markets are primarily net pool arrangements where majority of energy is traded through bilateral contracts (with residual energy traded in a balancing market. In this environment forward markets provide an important mechanism for developing a transparent reference price for financial markets and trading
2	The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?	We support the concept of a Unit Commitment for Security (UCS) service, as it simply utilises existing information more effectively to improve scheduling existing resources under contract.
3	The difference between actual and forecast residual demand leading up to real-time dispatch has been far more stable in the last decade than the difference between actual and forecast prices ($MWh) leading up to real-time dispatch. What do you consider the drivers of this may be?	NA.
3. 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	We are very supportive of the ISP as a framework for delivering a more strategic and proactive transmission planning framework relative to what existed previously. Ultimately however,

	implementation can be made more efficient and timely?	where consumers are expected to pay, the approval process (i.e. the RIT-T) for new transmission will be lengthy, complex and contentious. For example, project Energy Connect was first proposed in 2016 and final approvals (including contingent project valuation process) will not occur until late 2020. The length of the approval process means initial costings have now had to be revised and have almost doubled, which have putting at risk the final approval of this very important project. We consider the ESB's REZ framework will provide an important complement to the ISP and existing RIT-T process, as it will allow for greater flexibility in terms of the business models that can be applied for the deployment and operation of REZ transmission projects. This ranges from a regulated delivery model, where actionable REZ projects identified in the ISP are funded by customers (because they pass the RIT-T) to innovative private delivery models for those projects unlikely to pass the RIT-T. This might occur in circumstances where future projects in the ISP are brought forward due to developer interest (ISP development opportunities), or alternatively, private developers are seeking out non-ISP transmission projects within an existing or new REZ (i.e., large dedicated connection assets or DCAs)[6]. The incentive for private investment in transmission will be potential benefits to the investors that are not available for regulated projects. This could include firm connection dates, firmer access to the grid and fixed loss factors. Transgrid's New England Connection Capacity Auction (NECCA) we believe is a good example for how such a model may be implemented. In light of the AER's recent amendments to the Cost/Benefit guidelines for the RIT-T, this now also introduces scope for mixed deployment models, i.e., where transmission development projects comprise part regulated and part privately funded capacity (i.e. by governments or infrastructure funds etc). This might in fact now be necessary to get Project Energy Connect over the line!
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?	Increasing demand for transmission assets and components around the world to support the energy transition mean costs will continue to increase. In our view there will need to be an increasing reliance on private or mixed funding models as described in our answer to Question 3.1 above.

[6] However, we note here that the AEMC's proposed changes the DCA rules with respect to classification of connection points will be essential for this model to work effectively (so that separate performance standards can be negotiated for each connection point on the DCA).

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?	We consider the planning arrangements for REZs developed by the ESB provide a sound framework for planning of REZ projects. The Jurisdictional Planning Bodies should be responsible for planning, however deployment and ownership should be available to third parties to ensure competition and private incentives to develop large DCAs. The NECCA model is a good one. We note that Transgrid has set up a ringfenced contestable transmission business to implement the relevant infrastructure. We look forward to the ESB progressing its phase 2 work program on REZ development that can be applied across the NEM and which sets out *iner alia* details regarding: • Ownership models • Cost allocation framework • Firm access/loss factors • Open season/auction process We consider that one area that requires further consideration (we note that the AEMC has moved away from this) is the potential for new or incremental privately funded investments to receive a free allocation of FTRs, to ensure generators who pay for transmission received firm access to market. This would provide an important additional spur to private investment in transmission infrastructure, that we consider will be essential to support the efficient and timely development of REZs.
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?	Modelling the likely benefits of introducing LMP and FTRs is a highly complex exercise. While we disagree with some of the assumptions underpinning the analysis, we do agree with the overall conclusion that existing arrangements will significantly increase costs to consumers in an environment of inadequate locational signals and increasing levels of congestion. From our perspective, the key issue is the impact of poor locational signals and congestion on generator competition over increasingly scarce transmission capacity. Spectacularly, NERA's modelling suggests some 20,000 MW of renewable generation capacity that would have entered the market by 2040 in the absence of more efficient locational signals is avoided under the reform scenario, with significant increases in capacity factors of those generators that remain. While the numbers are most surely open to debate (particularly give high simplified bidding assumptions of the model), the key take away from our perspective is that the LMP discourages precisely what is of most concern under the existing arrangements, the excessive

		clustering of new generators in specific locations, causing excessive competition for scarce transmission capability and reductions in loss factors. We also note that the cost of transmission infrastructure and components, which has already increased substantially in recent years, will only continue to do so as demand for it increases around the world to support the global energy transition. It simply will not be feasible for transmission to resolve all congestion in the grid. Congestion will inevitably increase significantly over the coming decades, so it will be critically important to implement that right locational signals to support more efficient generator locational decisions, to ensure future congestion is minimised. The sheer volume of committed and uncommitted connections in the West Murray region is a clear example that existing location signals are not working. It also illustrates a key potential role of LMP pricing for providing clear and transparent information to developers for where, and where not, to build their generators. Perhaps receiving less attention, but also important is the impact of poor locational signals on exposure to loss factors. Like congestion, the impact of new connections on loss factors in a region is shared equally between all generators within the region. A newly connection generator therefore impacts the level of access to market of existing generators in the area, by increasing congestions and losses. In our view, these impacts are unpredictable and impossible to manage.
5	The AEMC has released an updated technical specification paper on the transmission access reform model, alongside this report. The updated proposal provides additional information on the options regarding the design of the instruments, pricing, and trading. How well do you think the proposal would address the identified challenges?	We are broadly supportive of the new framework set out by the AEMC. The key weakness from an overall policy is the lack of an explicit nexus between privately funded transmission investment and FTRs. In light of the scale of transmission investment required to support the energy transition, particularly with respect to REZ, the framework should encourage private investment in transmission infrastructure as much as possible. Allocating FTRs for free to private investors would significantly enhance the incentives for private investment.
6	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 do not consider the existing suite of location signals are sufficient. The current regional approach to pricing disguises where constrained parts of the grid are. The West Murray areas is clear example of this and where an LMP framework would have transparently signalled ahead of time the revenue risks of locating in this part of the network, which may have led to a much lower volume of subsequent connections in this areas, in the absence of further transmission expansion. We are seeing similar issues in south western NSW. It's partly a transparency issue, and partly also a recognition by new entrants that it may be worth accepting some curtailment risk given they can still access a high regional price. Further,

		under the NEM's pro-rata sharing mechanism, curtailment risk due to congestion is shared equally among all generators who sit behind a constraint, regardless of when they made their investment decision. Under the current model newly connecting generators can erode the level of access of existing generators over time. To date this has not been a serious issue in the NEM, however this will become an increasingly prevalent issue with some 30,000 MW of new generation capacity expected to enter the market in weaker parts of the grid (where the best renewable resources are located). Once congestion become entrenched and prevalent it could kill investment.