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Mr John Pierce
Chair
Australian Energy Market Commission
PO BOX A2449
Sydney South NSW 1235

Via online submission

Dear Mr Pierce,

RE EPR0073: COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT – ACCESS REFORM

TasNetworks welcomes the opportunity to make a submission to the Australian Energy Market Commission's (**AEMC's**) Directions Paper on the Coordination of Generation and Transmission Investment – Access Reform.

As the Transmission Network Service Provider (**TNSP**), Distribution Network Service Provider (**DNSP**) and jurisdictional planner in Tasmania, TasNetworks is focused on delivering safe and reliable electricity network services while achieving the lowest sustainable prices for Tasmanian customers. TasNetworks is also currently assessing the feasibility of Marinus Link, a second Bass Strait interconnector between Victoria and Tasmania. All of these roles require the prudent, safe and efficient management and development of the Tasmanian power system. TasNetworks is therefore supportive of AEMC's efforts to investigate access reform in a bid to improve and coordinate generation and transmission investment outcomes in the National Electricity Market (**NEM**).

TasNetworks supports Energy Networks Australia's (**ENA's**) submission and would like to make a number of further comments for the AEMC's consideration. The key points in this submission are:

- TasNetworks agrees with the AEMC on the need for access, charging, connection and planning reform to improve customer outcomes as the energy industry transition occurs. At a conceptual level, TasNetworks considers the AEMC's access reform is targeting some of the areas of the current framework that will promote such outcomes.
- However, and although acknowledging the access model is yet to be finalised, thus far, TasNetworks sees considerable conceptual and technical challenges with it. This includes its interrelationship with the broader regulatory reform agenda.
- TasNetworks acknowledges the AEMC's efforts on access consultation to date. It has been broad and encompassing. However, it has not been deep. Many discussions have been on only selected topics, have often been time constrained and have lacked the detail required to generate consensus and/or allow proper evaluation and analysis. This has been in stark

contrast with previous reviews such as Global Settlement or the Generator Technical Performance Standards reviews where there was considerable, unhurried investigation and deliberation on the more technical aspects of, and implications from, the proposed changes.

- TasNetworks considers the lack of depth in consultation to this point has been a factor of the highly aggressive consultation time frame. The AEMC is proposing fundamental reform that will impact almost all aspects of the NEM. However, many of the issues are the same as those that have not been resolved in many previous, related reviews which have spanned years of consultation.
- To date, there has also been little substantive detail for how the proposed model is to be integrated with the Energy Security Board's (**ESB's**) forthcoming Post 2025 Market Design Reform (**MD 2025**). Although other reforms such as 5 Minute Market Settlement (**5MS**), Global Settlement (**GS**), Wholesale Demand Response (**WDR**) and the Marginal Loss Factor (**MLF**) consultation are referenced at various points in the directions paper, there is a paucity of particulars on exactly how the proposed access changes may affect, and be affected by these reforms.
- Formally, there has been no information on when there will be an attempt to quantify the costs, benefits and risks of moving from the existing framework to an alternate one. Without having a full and final framework decided and accepted by industry, including an implementation plan illustrating how any proposed changes will alter or align with the forward regulatory reform program, TasNetworks cannot see how a comprehensive or accurate Cost Benefit Analysis (**CBA**) can be performed.
- Although appreciating the need for change, TasNetworks sees greater risks from poor policy resulting from rushed and ill-considered consultation, particularly to customers. TasNetworks considers the points above need to be addressed as a priority so that measured, principled and appropriate reform in the long term interests of customers results.

TasNetworks offers further feedback on the directions paper below so that the proposed framework can be made more workable. We would welcome the opportunity to discuss this submission further with you. Should you have any questions, please contact Chantal Hopwood, Leader Regulation via email (chantal.hopwood@tasnetworks.com.au) or by phone on (03) 6271 6511.

Yours sincerely,

Wayne Tucker

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Locational Marginal Pricing

Rationale

TasNetworks considers that allocative efficiency is best promoted when prices for a good or service reflect the marginal cost of provision. Conceptually, Locational Marginal Pricing (**LMP**) can be seen to be consistent with this. Although noting that forms of locational pricing are used to good effect in other international markets, the AEMC has not yet demonstrated that a deficiency in allocative efficiency in the NEM exists such that a move to LMP is required. Nor that the costs of doing so would not outweigh these benefits.

The AEMC has suggested that a reduction in 'race to the floor' disorderly bidding is the prime rationale for, and benefit from, favouring LMP over the current market pricing framework. As highlighted in the directions paper, the last publically available estimate of the benefit to reducing disorderly comes from ROAM Consulting's 2013 work. This forward-looking assessment concluded that disorderly bidding could save $8.8 million in net present value terms to 2030. Or put another way, less than a dollar per customer in total over 18 years.

Although the AEMC rightly points out this could be worsened in future by gaming with storage, no estimate of the magnitude of the possible effect has been provided. Lacking such an analysis, TasNetworks can only conclude that there is no compelling rationale for a move to LMP to address issues of disorderly bidding at this time. In this respect, TasNetworks suggests that further work is undertaken to quantify future costs and benefits of LMP to shore up any case for change.

Customer impacts

If a robust, quantitative case can be made for LMP to be implemented in the NEM, TasNetworks would support any excess settlement residuals going back to customers. This is primarily on the basis of consistency with the National Electricity Objective (**NEO**). However, TasNetworks notes that another advantage is that this would provide an incentive to generators to buy transmission hedges to access residues if some form of transmission hedging was enacted at the same time.

The AEMC has proposed that this be effected via a reduction in Transmission Use of System (**TUoS**) charges to customers. However, TasNetworks considers there is a risk that such an approach introduces unnecessary volatility in customer transmission charges similar to, or potentially in excess of, that witnessed with intra and inter settlements residues. TasNetworks' customers have consistently raised concerns about volatility in network charges and expressed a clear preference for sustainable and predictable pricing.

In the ENA's recent submission to the Marginal Loss Factors (**MLF**) consultation, a proposal to minimise the volatility of TUoS charges to customers was raised. This would involve the development of a distribution process for settlements residues which could be integrated into the market settlements process performed by the Australian Energy Market Operator (**AEMO**). TasNetworks suggests a similar approach should be considered by the AEMC for LMP residuals so that certainty in customer transmission charges can be maintained under LMP. That is, assuming LMP can be shown to have net benefits from adoption.

Who faces LMP?

The AEMC's answer to the question of who would face LMP has been settled on the basis of technical limitations with the National Electricity Market Dispatch Engine (**NEMDE**). This is instead of best practice economic principles or a consideration of other potential operating models. TasNetworks agrees that consistency between the pricing framework and the method by which the market is dispatched is a crucial aspect of any framework to ensure efficient market outcomes. However, it also needs to be consistent with the broader objectives of the access framework.

Under the AEMC's proposed approach, older intermittent generators that are classified as non-scheduled would face the Regional Reference Price (**RRP**). However, newer generators that are classified as semi-scheduled would face the LMP. This would mean that even though two generators could provide the exact same product, and could be located right next to each other, they would be remunerated differently for it. There is no economic efficiency based justification for this.

Further, if non-scheduled load or generation can elect to be scheduled, and thereby face LMP, this may undermine the revenue adequacy hoped to underpin the transmission hedging component of the AEMC's proposed model. This may occur for two reasons. Firstly, from reducing the pool of funding settled at the RRP and, secondly, from cost-shifting induced gaming related to the size of installed generation. That is, from the different prices that generators would face above and below the current 30MW threshold that determines whether generation is scheduled or not. TasNetworks considers that similar concerns may also result from storage technologies depending on how charging and discharging are treated under LMP.

Marginal Loss Factors

In the same way that LMP needs to be consistent with the other elements of the access framework, it also needs to be compatible with the MLF framework. TasNetworks notes that international best practice is not to modify the settlement quantity of electricity by a loss factor. Instead, the locational marginal price itself is modified. Often times a Dynamic Loss Factor (**DLF**) that accounts for real time losses in transporting electricity is used.

Conceptually, TasNetworks considers that DLFs would increase the efficiency of the AEMC's proposed model. However, this is not without challenges. A move to DLFs would trade off accuracy in the physical calculation of losses with uncertainty to generators in terms of their bidding and resultant settlement prices.

It would also require further changes to AEMO settlement functionality, potentially including NEMDE. At the recent MLF conference in Brisbane AEMO indicated that implementing DLFs would take up to two years. AEMO subsequently indicated that this timeframe could be pushed out due to work on existing and future projects. These include GS, 5MS, LMP, WDR and/or a move to full nodal pricing.

Given the risks in terms of timeframe and interrelationships with other reform elements, TasNetworks suggests the AEMC rely on AEMO to provide its best estimate of the technical difficulty and resourcing required to effect these changes whether implemented singularly or together. In this manner, the practical efficacy of the proposed reform might be better assessed and inform the decision on whether particular elements are achievable now or are better contemplated as part of MD 2025.

Other considerations

TasNetworks agrees with the AEMC that, if a case for LMP to be implemented can be made, it should be introduced in tandem with some form of mechanism to allow generators to hedge the resulting price risk. A staged approach whereby LMP is implemented first would introduce unnecessary complication and increase financial risks to participants for what would seem to be little benefit.

TasNetworks considers that there should be no distinction between constrained and unconstrained generation in respect of the market variables each would face if LMP were implemented. For example, in the Market Price Cap (**MPC**) or how losses are calculated. It would be inconsistent to apply a different price cap to generation behind a constraint than elsewhere with the risk being perverse incentives are created that stymie efficient generation and transmission investment.

If LMP were implemented, TasNetworks notes this would also move the market closer to a fully nodal one. This is not uncommon internationally. If a fully nodal market is desired and/or is a possibility from MD 2025, then it would be important to consider whether the case for LMP can be made as a transitional measure. AEMO has indicated that NEMDE would have to be rewritten in its entirety to effect full nodal pricing. As such, there would seem to be little benefit from changing

NEMDE to facilitate LMP for only a few years if NEMDE would be rewritten for full nodal pricing a short time later.

On this point, TasNetworks acknowledges the conceptual economic efficiency of full nodal pricing but also recognises its many challenges. These include political acceptance, equity concerns for customers and hedging implications for generators amongst other concerns. TasNetworks simply highlights that further consideration of this factor may be desirous to better inform current deliberations.

Summary

The desirability and effectiveness of LMP turns on the interrelationship with a number of different elements. These include the MLF framework, other components of access reform such as transmission hedging, possible future NEM designs, technical feasibility, charging volatility to customer along with consistency and timing aspects of the broader forward reform agenda (MD 2025, GS, 5MS, LMP, WDR etc.). TasNetworks recommends that thorough consideration is given to these aspects, including a full CBA, before a final decision on implementing LMP is made.

Transmission Hedges

Transmission planning

As indicated above, TasNetworks agrees with the AEMC that if LMP is implemented some form of hedging mechanism must also be introduced. Currently, generators typically face volume risk from their operations but this would effectively be substituted for a price risk under LMP. The Financial Transmission Rights (**FTRs**) proposed by the AEMC would provide generators with an ability to manage congestion related price risks as well as a financial contribution that could be used to offset TUoS charges to customers. TasNetworks supports these objectives but does not consider that FTRs, as proposed, are also a panacea for guiding and funding transmission investment.

The assumption underpinning the AEMC's approach is that generators will buy hedges consistent with their risk profile that, in aggregate, will comprise a generator access standard that TNSPs and AEMO would be required to plan the network to[1]. The idea being that this will efficiently inform and direct the appropriate level of transmission investment. This assumption overlooks the fact that the economically efficient level of transmission investment is likely to be underdetermined with such a generator led development approach when compared to a system view.

The primary reason for this is competition. Any additional generator connecting in the same area will impact other generators whether they are constrained by capacity or security constraints or not. Firstly, by impacting MLFs and secondly by creating further competition in generation bidding. In this manner, the value of any hedge to a generator will depend on how much transmission is to be built that might attract or accommodate further generation. That is, the optimal amount of transmission capacity from the point of view of a single generator is almost certainly likely to be different from the amount considered optimal from a system perspective.

This point is reflected in international experience. There is no international electricity market where the AEMC's proposed approach has been used successfully to determine the economic or financial merits of transmission investment. Indeed there is academic research highlighting the difficulties with such an approach[2]. Similarly, the failure of the Scale Efficient Network Extension (**SENE**) rule change to drive any coordinated transmission development can be seen as a domestic example of the challenges with a generation led investment approach.

[1] AEMC, *Coordination of Generation and Transmission Investment Directions Paper*, 2019, p.74.
[2] H Fraser, *Can FERC's standard market design work in large RTOs?*, Electricity Journal, July 2002.

TasNetworks therefore considers that it is absolutely critical that any FTR framework integrates within, rather than drives, the current planning regime. This includes the recently agreed changes to action the ISP that see AEMO and TNSPs working collaboratively through the ISP and a linked Regulatory Investment Test for Transmission (**RIT-T**) framework to efficiently and effectively plan and implement least regrets transmission investment.

NEM applicability

Beyond the critical questions of exactly how FTRs might integrate and/or inform the planning framework, TasNetworks considers the applicability of FTRs to the NEM requires further rigorous assessment. International experience has shown that it is not practicable to have separate transmission owners issuing and underwriting transmission hedges in the same interconnected and meshed network. That is, where flows in a separate region can create constraints, and therefore financial obligations, in others. From a Tasmanian perspective, this is no better illustrated than with Basslink operations where events on one side of the interconnector can cause impacts on the other, including the triggering of System Protection Schemes (**SPSs**).

To date, it is only where one central party has the power to decide and set transmission hedging allocations that FTRs have been successfully applied. For example, in New Zealand and certain parts of the US. It would therefore represent a fundamental shift in NEM operation if it was considered necessary that AEMO should solely fill this role. Without input from TNSPs along the lines of the current planning arrangements, this could have major consequences for jurisdictional planning and network operations.

In this respect, TasNetworks suggests that long-term hedges for new transmission investment should be issued by the relevant TNSP in conjunction with the current planning processes at the point where the expected optimal transmission investment has been identified. Note, that these hedges should not drive the planning process with investments in the shared network continuing to be determined through the ISP and regional planning practices. In contrast, TasNetworks considers shorter term hedges for the existing transmission system should be offered by AEMO in its role as independent market operator.

Valuation

The AEMC has proposed a fair value approach to pricing transmission hedges outright or for setting reserve prices for any auctioned FTRs. The valuation methodology proposed is based on the long-run forecast differences between the RRP and LMP. This fair value approach differs from the Long Run Incremental Cost (**LRIC**) model that was evaluated and ultimately abandoned under the previous Optional Firm Access (**OFA**) review, in that the marginal costs of transmission are excluded. Although this may help to resolve pricing for Tasmania where it couldn't be achieved under OFA, the fair value approach shares many of the same shortcomings.

Basing prices on long-term simulations of energy market locational prices would be contentious, economically inefficient and ultimately impractical. This is because there is no way of accurately assessing and forecasting the likelihood, location and impacts of transmission security and stability constraints *over the long term.*

TasNetworks is aware that Transpower (the New Zealand system operator) incorporates a forward looking system security forecast into the model that informs its FTR capacity auctions. However, in recognition of the complexities associated with such forecasting, it is only provided on a three year basis across eight nodes. This is orders of magnitude simpler than the AEMC's proposed fair value approach which would require computation of thousands of constraints equations across hundreds of NEM nodes on at least a decadal timescale. Aside from the costs associated with such a computationally complex undertaking, modelled values will inevitably differ from reality creating winners and losers. The risk being that it will ultimately be customers in the latter category.

The rationale for a fair value approach is ultimately linked to its use in determining transmission investment. As demonstrated above, using FTRs to mandate the required level of transmission investment is misguided. TasNetworks therefore strongly recommends that the fair value approach not be included in any FTR framework. Instead, TasNetworks advocates that this approach is supplanted with a market based mechanism that allows the interactions of buyers and sellers to set prices without interference from any central valuation methodology or authority.

Incentive scheme

Conceptually, TasNetworks agrees that an incentive scheme on TNSPs is required as part of a holistic approach to the FTR issues the directions paper is seeking to address. Without it, generators and customers may lack the confidence that hedge payments are being used in their interest. That is, to underpin sufficient network investment to promote the efficient, secure and reliable supply of electricity.

However, TasNetworks sees several risks with such an approach. As demonstrated above, the idea that the efficient level of network investment will be consistent with the quantity of hedges sold is invalid. As such, it is not clear how an incentive scheme built on this premise could also be efficient.

It is difficult to see how an incentive and/or penalty scheme can be equitably applied in an interconnected network where actions in one region may affect and create financial obligations in another. In the Tasmanian context, SPSs are a particularly relevant example. TasNetworks operates several of these schemes which are used to protect on island generation and transmission from off island contingencies that result in the loss or temporary de-rating of Basslink. Such events would have LMP impacts as various generators are constrained on or off to address system security concerns. It would therefore seem highly inequitable that TNSPs would be penalised for not meeting their FTR capacity obligations as a result. That is, for operating a mechanism to maintain secure and reliable electricity supply.

In order to avoid this, hedging volumes would need to be set very conservatively. This would drive a further wedge between the value obtained from the sale of transmission hedges and the costs and values of the underlying transmission assets. TasNetworks contends that careful consideration of the design of any new incentive scheme, and/or its interaction with the Market Impact Component (**MIC**) of the Service Target Performance Incentive Scheme (**STPIS**), is therefore required.

Transitional considerations

TasNetworks agrees with the AEMC that transitional arrangements including issues of grandfathering will be of paramount importance in deciding the viability and acceptance of any proposed reform. TasNetworks also agrees with the AEMC's principles as a means for guiding the development of any transition plan. However, as was demonstrated in the OFA review, assigning rights over existing network to incumbent generators is fraught with issues and complexity. If not set at an efficient level, incumbent generators will be advantaged at the expense of future generators or vice versa. Either way, the risk of compromising further efficient investment is high.

Despite numerous attempts and years of consultation, no workable and supported model or mechanism has emerged for assigning such rights over existing network infrastructure. TasNetworks notes that there is only one Technical Working Group meeting scheduled before the draft CoGaTI position is due in September. TasNetworks also notes the ESB's MD 2025 Technical Working Groups and the AEMC's CoGaTI Charging paper are both also due before then. With no beginnings of a position or solution having been put forward by the AEMC on transitional arrangement to date, TasNetworks is extremely concerned that this issue will not see sufficient analytical time to result in a robust, efficient and equitable solution.

Summary

TasNetworks agrees that some form of hedging arrangement is required if a move to LMP is desired and can be demonstrated to be beneficial to customers and the broader market. As the above has highlighted, however, the issues associated with transmission hedging are fundamental and immensely complex. There is a substantial amount of detail yet to be provided (terms and types of hedge products, how sold, for what duration etc.), let alone fully considered in the context of the broader transmission investment framework such as the ISP, MD 2025 and other ongoing reforms.

TasNetworks sees extreme risks of poor policy outcomes for multiple stakeholders if the current consultation is not undertaken thoroughly. TasNetworks therefore suggests that sufficient time be given to properly assess the issues and implications from the AEMC's proposed model. Critically, and as above, this timeframe needs to incorporate a rigorous cost, benefit and risk assessment to ensure that any proposed changes provide value to market participants, particularly customers.

Renewable Energy Zones

Open season windows

Open season windows have been advanced by the AEMC for better coordinating the investments of individual generators to promote Renewable Energy Zone (**REZ**) development. TasNetworks notes that open seasons have been tried with varying degrees of success in different industries and parts of the world. For example, gas pipelines in the US, transmission and distribution developments in Europe and communications infrastructure development in Asia. TasNetworks considers that open seasons could be relatively straight forward to introduce in Australia. Further, that they could be incorporated within the FTR regime proposed by the AEMC or an alternative access model.

Despite this, TasNetworks considers open seasons would have limited effectiveness for underpinning REZ development, particularly in Tasmania. In the first instance, open seasons risk further exacerbating the lag in transmission development timeframes. In areas where there are already high volumes of development applications, this may not be problematic. A short window might result in sufficient coordination that REZ development is not impeded. However, in other places and times, a longer window may be required to properly ascertain and achieve the required level of commitment. For example, where different generation types are proposed in the same area or where different legislative, funding or environmental considerations are applicable to different generators.

The risk is that without a sufficient season that recognises and accounts for these differences, no generator coordination results. Conversely, in having too long a window generators may be deterred from investing at all. In this respect, a fixed, one size fits all approach to window size and evaluation is unlikely to be practical and risks derailing development that might otherwise occur. TasNetworks therefore recommends that if open seasons are to be used, TNSPs have the flexibility to set the length of the window based on their unique understanding of their local jurisdictions.

Beyond this concern, TasNetworks notes that an open season may have to be accompanied by a restriction on generators connecting outside a REZ. For example, in those situations where transmission investment to open up a REZ incentivises additional incremental generation investment outside of the REZ along the same flow path. This may not be feasible given current access arrangements, nor desirable depending on the technical characteristics of the particular transmission network. Moreover, it could lead to investment being stymied inside the REZ.

For these reasons, TasNetworks considers that open seasons can only be, at best, a supplement to other mechanisms for facilitating REZ development rather than an option in its own right.

PIAC model

TasNetworks notes the efforts of the Public Interest Advocacy Centre (**PIAC**) in developing a cost recovery model to underpin REZ development. However, TasNetworks does not support it. The core proposition of the model is that the price for generation access will be lower for parties connecting earlier, rather than later, and with the prescribed efficient size of a REZ determined by AEMO as part of the ISP. TasNetworks notes that TNSP investment could not be less than this efficient size, even where the TNSP had more accurate and up to date information which indicated expected future generation was likely to be less than that indicated in the ISP. Ultimately, this would create a fundamental disconnect between the party bearing the risk (the TNSP), the party who determines the extent of that risk (AEMO) and the party who decides on the compensation for bearing that risk (the AER). This disconnect can only be expected to lead to suboptimal investment outcomes.

Further, the proposition that customers should pay 50% and generators pay for the remaining 50% of development costs has no efficiency based justification. Aside from leaving customers with a bill to pay that may not be seen under alternative models, it may also discourage, rather than encourage, generator commitment when compared to other models.

The PIAC model presumes that REZs can and will continue to be distinguished from the shared network. In an increasingly interconnected, looped and meshed transmission system, this is unlikely to hold true into the future. This raises serious issues about competition, pricing and revenue differences between regulated and unregulated parts of REZs and the broader transmission network. To date, these implications do not appear to have been considered.

The model is further complicated by the introduction of a new government counterparty. This alters the risk allocation in two ways, neither of which is desirable. Firstly, as taxpayers would bear risk associated with a portion of the ‘at risk’ investment. But secondly, because tax payers would also benefit where generator connections were above the ‘efficient capacity’ level as determined in the ISP. This would reduce the benefits to TNSPs from additional connections and thereby raise the financial risks profile from investing in excess capacity. That is, it is only likely to lead to less transmission investment on the behalf of TNSPs rather than more.

Finally, it is not clear how the PIAC model could or would apply or transition to the LMP/FTR model proposed by the AEMC if this were to be instituted. Given this, and the reasons provided above, TasNetworks recommends that no further consideration of the PIAC model takes place as part of the CoGaTI access review.

Alternative models

TasNetworks considers the ESB’s mooted adjustment fund may provide one alternative mechanism for facilitating REZ development. Using the fund to build transmission infrastructure to REZs would help to solve the so called ‘chicken and egg’ investment dilemma[3]. It would also have the advantage of not having to solve the generator coordination problem. However, tax payers would bear the costs of any inefficient investment. Given this, TasNetworks suggests that use of the fund be limited to cases in which ISP analysis shows that, even with lower levels of generator connection, the transmission investment is still beneficial from a system perspective.

The use of some form of down payment or transmission bond arrangement may be another viable vehicle for promoting REZ investment. Under such an arrangement, generators would signal their development intentions by putting up a financial commitment, some portion of which would be refunded once those generators had connected to the developed REZ. This approach could be combined with open season windows to better assess and coordinate generation commitment. It might also be used in conjunction with the ESB’s adjustment fund to underwrite bonds for

[3] Where generators are unwilling to commit to a REZ without transmission infrastructure being built but where such commitment is required for projects to pass a RIT-T to allow TNSPs to build it.

generators. In lowering financial risks to generators, this would also mitigate market power and competition concerns that might otherwise see only larger, better capitalised proponents utilise transmission bonds to effect REZ developments.

Other reviews

The concept of REZs has been considered as part of the SENE rule change and by AEMO as part of the ISP. In addition to the AEMC's current deliberations, TasNetworks understands the ESB will be consulting on this issue in the near future as a part of, or prelude to, MD 2025. TasNetworks is also aware that the Australian Renewable Energy Agency (**ARENA**) is working with a private consultancy on a separate project to evaluate and inform the REZ debate which is also due soon. Given these developments, TasNetworks suggests final decisions on how best to develop REZs are not made until such time as the learnings from these separate pieces of work are available for consideration.

Summary

TasNetworks agrees with the AEMC that more effective development and investment commitment measures for REZs are required. With their inherent scale efficiency, REZs have the potential for lower costs consumer outcomes than any decentralised process for obtaining generator commitment. However, issues of cost and risk sharing, market power and competition impacts require careful consideration to ensure equitable and economic REZ development outcomes.

TasNetworks considers there are a range of models and elements that could address these aspects. However, TasNetworks contends that these can only be an addition to, and not a replacement for, effective transmission planning and investment. The interaction between REZ development models, the current planning framework and other REZ investigations needs appropriate consideration. As above, sufficient time, investigation and quantification of risks, costs and benefits of any proposed reform must be judiciously weighed before any decision should be made in order that the optimal, least regrets and least cost outcomes to customers are delivered over the long term.