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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: COGATI IMPLEMENTATION - ACCESS AND CHARGING

TasNetworks welcomes the opportunity to make a submission to the Australian Energy Market Commission's (**AEMC**) consultation paper on *COGATI Implementation - Access and Charging*. 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. This requires the prudent, safe and efficient management and development of the Tasmanian power system. TasNetworks is therefore supportive of the AEMC's efforts to reassess access arrangements in the National Electricity Market (**NEM**).

TasNetworks is conducting a Regulatory Investment Test for Transmission (**RIT-T**) for Marinus Link, a proposed second Bass Strait interconnector between Tasmania and Victoria. Economic modelling indicates that Marinus Link would primarily benefit consumers in mainland NEM regions. However, the current cost recovery arrangements would need to change for the link to proceed as a disproportionate share of the costs of the link, and associated supporting transmission network investment, would be borne by Tasmanian electricity customers. Both TasNetworks and the Tasmanian Government[1] have recognised the need for changes to network pricing frameworks to ensure beneficiaries pay for the services they receive. In this respect, TasNetworks is particularly supportive of the AEMC's efforts to review Inter-Regional Transmission Use of System (**IR-TUOS**) charges in this consultation.

TasNetworks supports Energy Networks Australia's (**ENA**) submission and would like to make several additional comments with a particular focus on the Tasmanian context. The key points in this submission are:

- TasNetworks considers it essential that customer outcomes are a key focus of the access and charging review. In this regard, TasNetworks suggests a rigorous and transparent cost benefit analysis is conducted to provide certainty to customers and market participants that the proposed access and charging reforms are in their best long term interests and consistent with the National Electricity Objective (**NEO**). The information provided in the consultation papers to date has not adequately addressed this concern.

[1] *Marinus Link Battery of the Nation Current Situation Report*, Tasmanian Government Department of State Growth, February 2019.

- TasNetworks agrees with the AEMC's assessment that current access and charging arrangements do not resolve concerns associated with disorderly bidding and congestion that are arising as the NEM transitions to a lower carbon generation mix.
- TasNetworks also agrees that access reform incorporating Dynamical Regional Pricing (**DRP**) could be one method to help to address these issues and lower costs to customers. However, TasNetworks acknowledges this could have significant ramifications for market participants. If broad support for such a reform is lacking, particularly from the generation sector, TasNetworks considers the viability of the reform agenda would need to be reassessed.
- TasNetworks sees great risks in moving beyond DRP and adopting a firm access model that too closely resembles the Optional Firm Access (**OFA**) models that have been the subject of past deliberations. As discovered in the 2015 OFA review, there are a plethora of problems that mean implementation of such a model would be extremely challenging.
- It should be noted that previous OFA modelling was unable to produce indicative pricing in Tasmania owing to Tasmania's unique power system characteristics. The issues around system security constraints have become more complex with the passage of time. Moreover, these issues have become more prevalent in the rest of the NEM. TasNetworks does not therefore consider that a firm access model of the type previously advanced under the OFA review could be usefully implemented in Tasmania or elsewhere in the NEM now.
- TasNetworks considers that the proposed approach to the timing and phasing of access reforms is ambitious. Despite 13 previous reviews, several firm access issues have remained intractable and are, if anything, only more contentious now. For example, the degree of firmness able to be provided by TNSPs to generators, the attendant value to generators and how the risks, and compensation for risks, to TNSPs could be managed.
- TasNetworks contends the proposed, incremental changes to existing IR-TUOS arrangements will fail to address the shortcomings of the current IR-TUOS framework. Moreover, it will be too slow to help in resolving the 'who pays' question for Marinus Link and the associated transmission investment. TasNetworks considers that allocating the costs of Marinus Link based on the benefits to end customers, or via the ESB's mooted adjustment fund, could be viable mechanisms for fairly allocating costs to those regions who are forecast to benefit.
- Similarly, given the interplay with other existing and mooted reviews, TasNetworks suggests the Energy Security Board (**ESB**) be tasked with coordinating the work of the various market bodies to ensure that a timely, integrated and balanced regulatory framework to access and charging is developed.

TasNetworks' responses to individual questions are provided below and we 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,

General Manager Regulation, Policy and Strategic Asset Management

QUESTION 1: PHASING OF ACCESS REFORMS

Is our proposed approach to phasing access reforms appropriate? Are the number and nature of the phases appropriate? How might access reform be phased differently? What interactions with other market design reforms throughout the sector, and the energy transformation more generally, should be considered when developing and assessing transmission access reforms? What should be taken into account when considering how to transition to these new arrangements?

TasNetworks agrees with the AEMC's assessment that current access and charging arrangements are failing to adequately address problems in the NEM arising from the transition to a lower carbon generation mix. Generators continue to make suboptimal locational investment decisions from a system standpoint with associated congestion resulting in inefficient dispatch outcomes.

In principle, a move to firm access rights via an earlier implementation of DRP, and in conjunction with the Integrated System Plan (**ISP**), would seem an economically elegant and efficient phasing of reform to address this issue. However, as detailed further below, TasNetworks sees great risks from moving beyond this to adopting a firm access model that too closely resembles those of previous reviews. As discovered throughout the 2015 OFA Review, there are a plethora of practical considerations that mean implementation of such a model would be extremely challenging.

TasNetworks acknowledges the AEMC's comments in the supplementary information paper with respect to ESB's *Post 2025 Market Design* consultation. TasNetworks notes, however, that it is still not clear how these two reviews will work together given the level of overlap between them. It would seem a highly inefficient outcome to consult twice on market design issues, particularly if pre and post 2025 market design considerations conflicted such that there was no appropriate and actionable transition path between them. To avoid this, TasNetworks suggests the ESB is tasked with coordinating the work of the various regulators to ensure that a timely, holistic and balanced regulatory response to access and charging issues results.

QUESTION 2: PHASE 1: DYNAMIC REGIONAL PRICING

What is the nature of the risk on generators from being settled at the dynamic regional price in the event of congestion? To what extent is this risk different from (and greater or less than) the current risk to generators of being constrained off/down in the event of congestion? What impact may these changing risks have on the contract market, both in terms of products, liquidity, and risks businesses are exposed to? Is generator capacity an appropriate metric on which to allocate the settlement residue which arises from dynamic regional pricing? If not, what alternative metric should be used? Which particular measure of capacity should be used (e.g. nameplate capacity, maximum output in previous X years)? How might the use of capacity or another metric create distorted incentives for generators and/or storage devices? Should storage, when importing from the grid, be settled at the dynamic regional price? What might the effects of this be? What issues or unintended consequences might arise? What are the nature and extent of implementation costs, such as system changes (e.g. settlement reallocations), that would be required to implement phase 1?

In terms of DRP and disorderly bidding, TasNetworks acknowledges and agrees with the AEMC's comments in the Supplementary Information Paper that different types of disorderly bidding exist. TasNetworks also considers that the potential for the frequency of disorderly bidding may rise as the frequency of system security constraints increases. Similarly, TasNetworks also considers that, in principle, DRP may be one method for tackling this issue.

However, TasNetworks notes that the examples of DRP in the consultation paper are highly simplified for the purpose of illustration. In order to truly understand the risks and likely outcomes of DRP, further, detailed consideration needs to be given to real world situations where multiple and differing constraints, e.g., thermal, stability and Frequency Control Ancillary Services (**FCAS**) constraints, can simultaneously impact generators in a meshed network. Such an analysis should not only consider the power system as it stands now but also a potential future power system with higher quantities of variable renewable energy resources.

Similarly, in assessing the treatment of storage, detailed analysis of the response of storage across many dispatch intervals must be performed. The examples given in Figures 6.4 and 6.5 in the Consultation Paper represents only one dispatch interval and assume a fixed short run marginal cost for storage. This differs from reality in two key facets:

1. Storage cannot continue to generate indefinitely because it will need to recharge at some point. Thus the market behaviour of storage in the face of constraints would be expected to differ significantly from generation types with effectively unlimited input energy.
2. The resource cost of storage when operating as a generator is not fixed. Rather, it is based on the price at which the storage can be charged plus round-trip losses.

The examples in the consultation paper also include a compensation payment with DRP. This differs to current regional pricing arrangements where this mechanism does not exist and where pricing between regions can diverge thus offering informational pricing signals. TasNetworks therefore queries whether compensation payments are required to extract the proposed benefits from DRP.

Beyond these considerations, and as noted in the AEMC fact sheet on disorderly bidding, there is no recent quantitative analysis indicating either the magnitude or severity of different types of disorderly bidding. Lacking such an analysis, it is unclear whether there is a net market benefit to reducing disorderly bidding, or whether there is need for further reforms beyond those already in train to address aspects of this issue, e.g. the move to 5 minute market settlement. In this respect, TasNetworks suggests that the access and charging reform agenda be subject to a rigorous and transparent cost benefit analysis to provide some measure of certainty to customers and market participants that the proposed reforms are worth pursuing.

TasNetworks acknowledges the AEMC's comments in the Supplementary Information Paper pertaining to Marginal Loss Factors (**MLFs**). TasNetworks considers that the inclusion of dynamic MLFs in dispatch calculations under DRP may provide additional and timelier locational signals to generators beyond those provided by current MLFs. This could help to reduce costs to customers in the long term. However, this would mark a substantial departure from current market practice and would introduce a new form of price risk in addition to the already existing volume risk. The viability of participants to reliably and cost effectively hedge this risk is therefore a key matter warranting further deliberation. Lacking appropriate contracts, or other hedging mechanisms, there is a risk of increased wholesale prices and price volatility in those regions with relatively more constraints. Neither of these outcomes would be in the long term interests of customers.

It is also not clear how DRP will help to influence generator locational decisions or disorderly bidding if the constraint is anything other than a persistent thermal capacity constraint in a localised area. TasNetworks acknowledges the AEMC's recognition of this issue in the Supplementary Information Paper and considers it vital that further analysis of more complex constraints be conducted to inform a decision on DRP. At a minimum, such analysis should cover:

- stability based constraints which impact a wide area of the network and potentially entire regions;
- thermal constraints on transmission lines with dynamic ratings that are calculated on a real time basis; and
- frequency based constraints.

In this regard, it should be noted that historical constraint analyses are of little use in predicting future constraints. For example, and as acknowledged in the AEMC's recently released Annual Market Performance Report, frequency and other stability constraints are occurring in new locations in much greater numbers as the NEM transitions to an increasingly intermittent and asynchronous generation mix. This is particularly important in the Tasmanian context where owing to the unique characteristics of the Tasmanian power system, whole of system technical limits, that are completely independent of local network capacity, are more likely to see generation constrained. TasNetworks therefore suggests that before DRP is implemented, representative trials occur in such jurisdictions to assess the likely value or otherwise from DRP.

QUESTION 3: INFORMATION FROM DYNAMIC REGIONAL PRICING
What information is likely to be revealed through dynamic regional pricing? How valuable is the information from dynamic regional pricing likely to be in the various transmission planning processes? Will it have other uses? How should the information revealed by dynamic regional pricing be revealed to the market? How might AEMO, TNSPs and the AER integrate the information into their processes? Should the rules be modified to require these parties to take this information into account, and if so, how?

TasNetworks considers that DRP may provide some congestion pricing information to inform locational generation decisions at already congested points in the network. However, the incremental value to this information might be limited. TasNetworks notes that information on congestion and its valuation is already available from a number of sources, including Annual Planning Reports, RIT-T reports and AEMO Market Constraint Reports[2].

Moreover, DRP will reveal nothing about the potential future pricing impacts from new entrant generators or ascribe value to transmission assets when not constrained. It will therefore be of limited value in resolving TUOS pricing concerns. In this respect, it is not clear what sway DRP might have on generators and their locational decisions when quality of fuel resource, land costs and land access concerns are likely to have just as much, if not more import.

The AEMC has proposed that generators would be able to fund transmission infrastructure from 2023 based on the information obtained from DRP which is proposed to be implemented in 2022. This timeframe is likely to be inadequate in the Tasmanian context. That is, with hydro generation being the dominant form of electricity production, it will not be possible to separate the effects of DRP on congestion from system impacts related to changes in rainfall. At a minimum, this would likely require years of data before any definite conclusions on the revealed costs of congestion from DRP could be drawn that would provide sufficient certainty to generators on whether to fund Tasmanian transmission investment.

QUESTION 4: GENERATORS FUND TRANSMISSION INVESTMENT
What issues and considerations should the AEMC take into account when developing and assessing phase 3?

In principle, TasNetworks agrees with the AEMC that generators should pay for transmission infrastructure that is constructed for their benefit given this is likely to minimise costs to electricity customers. However, TasNetworks also acknowledges that generators will require a sufficiently firm access right as compensation. Depending on the model adopted, this may prove to be problematic. As was demonstrated with the previous OFA review, generator support for OFA dwindled over time as the complexities associated with it meant firm access, of the type favoured by generators, was unlikely to be guaranteed.

TasNetworks acknowledges that there are firm access models that differ to OFA that might be more viable from a conceptual standpoint. However, as has been evidenced by the dearth of projects

[2] TasNetworks notes that this report may not be as accurate as the others listed given it may also reflect the presently unquantified impacts of disorderly bidding.

commissioned under the Scale Efficient Network Extension (**SENE**) rule change, practical support over and above conceptual support is required for desired outcomes to eventuate. TasNetworks therefore suggests that if such practical support from the national generation sector is missing, the firm access reform agenda be re-evaluated.

Presuming support was forthcoming, it should be noted that the ability of generators to dispatch their full output will depend on many factors that are outside the control of TNSPs. The firmness of access, the costs to TNSPs to provide it and the attendant valuation by generators, requires further quantification. Without knowing this, it is hard to assess whether the benefits of access reform will outweigh the costs, particularly given the potential risks to generators from DRP (hedging) and to TNSPs (financial penalties) from firm access.

In this respect, TasNetworks considers that transmission access must be priced using a practical, equitable, transparent and universally accepted methodology that grants TNSPs sufficient revenue to alleviate constraints, to the extent reasonably necessary, as remunerates TNSPs for the additional risks that firm access might bring. Such compensation could take several forms. If regulated, this would likely require the Rate of Return to be consulted upon again given recent Australian Energy Regulator (**AER**) rulings have effectively mandated one rate of return for all elements of TNSP business. Alternatively, access could be auctioned and therefore be unregulated, however, the interplay with regulated assessment measures of network performance would need further consideration.

TasNetworks acknowledges the AEMC's comments in the Supplementary Information Paper on the possibility of a scheme for TNSPs to incentivise them to operate the network to minimise congestion. However, TasNetworks notes that the Market Impact of Transmission Congestion (**MITC**) component of the Service Target Performance Incentive Scheme (**STPIS**) already serves this purpose. It would seem highly inefficient to initiate a further regulatory review to duplicate something that already exists.

The AEMC also raised the idea of generators purchasing pre-determined loss factors for a fixed period of time in the Supplementary Information Paper. TasNetworks does not consider that this would be desirable or practically feasible. Decoupling the value of actual network flows from market settlements processes, even for a limited time, could create many complications. For instance, it is not clear how or who, ultimately, would end up paying for fixed MLFs that were higher than actual physical network flows would otherwise dictate. It is similarly unclear how the attendant impacts on other mechanisms such as settlement residues auctions could be managed.

TasNetworks notes the AEMC's comments on determining access rights for existing transmission assets. In principle, grandfathering arrangements would seem a legitimate method of allocating rights and aiding existing generators to transition to a new firm access model. However, it should be considered that no consensus on rights for existing transmission assets was able to be reached in the 2015 OFA review.

One issue not considered in either the original Consultation Paper or the Supplementary Information Paper concerns the issue of firm access and interconnection. At one level, interconnectors might be considered to be no different to any other transmission line. However, the market power and related system security implications from having one generator with all, or even the majority, of the access to an interconnector warrants further serious consideration.

Beyond these general considerations, TasNetworks notes that there a host of practical issues specific to Tasmania that would require robust investigation and deliberation before firm access arrangements could be confidently considered to be viable in Tasmania. These have been recognised previously by the AEMC. In section 14.2 of *Volume 1 of the 2015 Final Report on Optional Firm Access, Design and Testing*, the AEMC highlighted a number of jurisdictional characteristics unique to Tasmania that made OFA technically more challenging to implement. These included:

- the type and classification of constraints;
- connection point complexity;
- the location of the regional reference node; and
- the unique way in which Tasmania is connected to the rest of the NEM.

Combined, these issues resulted in the prototype pricing model being unable to produce indicative prices for Tasmania. Page VII of the executive summary of the same document sets out the AEMC's conclusion on OFA in Tasmania:

"If optional firm access was implemented, Tasmania should be excluded from the optional firm access model in the first instance, assuming elements of the Tasmanian market remain as they are currently. Relative to other regions, the technical challenges for optional firm access would be greater and the benefits lower in Tasmania. The nature of interconnection between Tasmania and the mainland also makes it easier to separate than all other regions".

In this respect, it should be noted that in the intervening years since the OFA review was completed, the rest of the NEM has become more like Tasmania. That is, and as acknowledged in the AEMC's recently released Annual Market Performance Report, frequency and other stability constraints are occurring in new locations in much greater frequency as the NEM transitions to an increasingly intermittent and asynchronous generation mix. For example, from the fault ride through behaviour of wind farms in response to temporary load and generation imbalances which can increase energy deficit, necessitate further system wide frequency response, and raise the risk of under-frequency load shedding.

Given this, TasNetworks does not see how a model resembling that proposed previously under the OFA review could be practically and efficiently applied in Tasmania, or elsewhere in the NEM, now. This was a view reinforced at the recent Tasmanian Generator Forum where support for a re-examination of OFA was gauged. Not one generator in Tasmania was supportive citing the costs, uncertainty and risks that OFA reform would bring.

TasNetworks is not aware of any international power system having successfully developed a market-based system of firm access rights for guiding and financing <u>all</u> transmission investment[3]. As a result, all international power systems continue to rely on a high degree of centralised coordination and decision making. This international experience should not be disregarded or dismissed on purely theoretical grounds given the critical practical implications for the NEM and the broader Australian economy from access reform. TasNetworks therefore strongly urges the AEMC to undertake further analysis and deliberation of these and related issues before any final decision to attempt to implement firm access, of any kind, is made.

QUESTION 5: ACCESS REFORM TIMEFRAMES
Are the timeframes suggested for the access reforms appropriate? Is the timing of the phases appropriate?

TasNetworks considers that the proposed approach to the timing of access reforms is highly ambitious. As acknowledged in the consultation paper, there have been at least 13 major reports and reviews dealing with various aspects of congestion management and generator access since NEM inception. Although progress has been made on some issues, others have to date proved intractable. As discussed above, this has included, but not been limited to:

[3] TasNetworks is aware that firm access has been applied selectively in certain US jurisdictions but never for financing 100 per cent of required transmission investment, or even the majority of transmission investment.

- transmission system constraints other than thermal constraints, e.g. those arising from inertia, FCAS and other system security considerations;
- pricing model complexity and limitations;
- risk allocation and incentive alignment amongst economic actors;
- accurate quantification and evaluation of the costs and benefits of reform including the costs of uncertainty on investment from a lengthy regulatory review; and
- questions of who should pay and how reforms are to be funded.

Even were these issues to be resolved such that a proposed framework was seen as workable, as detailed in question three, the second phase would be unlikely to provide any useful insight in the Tasmanian context in the timeframe envisioned.

QUESTION 6: IR-TUOS
How should IR-TUOS be refined? What are the answers to the specific questions raised above, or how might the AEMC go about answering these questions? What other considerations should the AEMC take into account when refining IR-TUOS?

One consequence of the transition to a decarbonised and renewables based electricity generation sector is that a significant quantity of new generation capacity is locating in areas of high fuel quality (wind and solar) but which are remote from load centres. The current basis for pricing transmission services does not support the equitable or efficient allocation of the costs of transmitting this energy across regional boundaries. For example, current IR-TUOS arrangements were developed on the basis of long run marginal cost pricing, with the Modified Load Export Charge (**MLEC**) methodology allocating the "locational costs" of transmission symmetrically between interconnected regions. Although this approach may reasonably capture asset utilisation, it does not necessarily reflect the relative benefits provided by an interconnector and associated transmission shared assets to each region, nor to the broader NEM. That is to say, to regions beyond those in which interconnection assets are physically located.

Previously, there has been a tendency for regulators to regard transmission pricing arrangements as a cost recovery mechanism that is distinct from the investment decision. However, as customers become more central to, and have more say over TNSP investment plans, these considerations are becoming increasingly intertwined. Should this trend continue, then there is an increased risk that projects that maximise national market benefits may not go ahead due to regional pricing concerns. The consequence being that other projects will then be required with the attendant loss of economic efficiency. This is no better illustrated than with the proposed Marinus Link interconnector where initial modelling indicates the majority of benefits will flow to mainland regions but where Tasmanian customers would pay disproportionately for it under current settings.

The incremental changes to existing IR-TUOS arrangements proposed in the consultation paper do not go far enough to achieve equitable distribution of costs across NEM regions. Allocating costs based on average load, including the non-locational component in inter-regional charging and/or discounting non-locational elements will do nothing to align costs with benefits provided to regions not symmetrically connected. Moreover, they could result in poorer customer pricing outcomes. For example, average load pricing could exacerbate pricing volatility in Tasmania and Victoria given the difference in transmission flows resulting from a wet versus a dry year in Tasmania, and despite peak use remaining largely the same from year to year. TasNetworks therefore considers that a broader, holistic review of IR-TUOS is required to ensure that equitable and efficient costs of interconnection are allocated proportionately to beneficiaries across all regions.

Notwithstanding the support for a longer term IR-TUOS review, TasNetworks highlights that the time required would not allow for the timely resolution of the 'who pays' issue for Marinus Link and associated transmission investment. In this respect, TasNetworks considers that there are other ways of resolving the 'who pays' issue for projects that have NEM wide benefits but have inequitable pricing implications when spread across only one or two jurisdictions. For example, the costs of such projects might be allocated proportionally via a NEM interconnection levy, charged by AEMO as part of its market fees, based on energy throughput across the NEM. TasNetworks also notes that the ESB has flagged an Adjustment Fund to pay for the extension of transmission networks to REZs, with the cost of the fund being progressively recovered from customers as utilisation increases. This might also represent another viable mechanism by which costs of interconnection and associated transmission infrastructure might be fairly and proportionally allocated to those who benefit.

QUESTION 7: TUOS FRAMEWORK

What insights do you have with regard to the above components of TUOS which you consider the AEMC should take into account when assessing TUOS reform? What other components of TUOS should be considered?

TasNetworks considers that current TUOS settings are largely appropriate but acknowledges that a broader review of TUOS settings may be required depending on the outcomes and challenges arising from elements of this and other reviews. For example, from AEMO's forthcoming rule change proposal on NEM storage registration and classification. In this regard, TasNetworks supports a TUOS review to the extent that it is necessary to achieve an integrated, balanced and transparent regulatory access and pricing framework.

QUESTION 8: TUOS REFORM TIMEFRAMES

Are the timeframes suggested for the TUOS reforms appropriate?

As with the answer to question 1 above, TasNetworks considers that the timeframes proposed are ambitious. History dictates that TUOS, particularly IR-TUOS, issues are difficult to resolve. Given the forward regulatory work program and interrelationship with access reform also proposed, this is likely to prove only more challenging at this time. TasNetworks suggests further consideration be given to the extending the proposed reform timeline.