COGATI access reform

Response to AEMC directions paper

2 August 2019

Energy Networks Australia

Contents

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Key messages

- Energy Networks Australia supports reforms to the access regime where they are in the long-term interests of consumers:
  - the objective should be to ensure consumers pay as low a cost as possible for a reliable and secure system as the generation sector transforms and decarbonises. However, it does not follow that simply reducing the direct investment risk borne by consumers will deliver this objective.
- Energy Networks Australia supports in concept the first two elements of the Australian Energy Market Commission's (AEMC's) proposed reforms:
  - improved locational price signals through the introduction of Locational Marginal Prices (LMP), which Energy Networks Australia considers should incorporate dynamic marginal loss factors; and
  - the provision of transmission hedges as a risk-management tool, to enable generators to achieve financially firm access to the wholesale spot market.

  These changes reflect arrangements that have been proven to work in other markets internationally. Further work is required in order to be confident that these arrangements can be successfully implemented in the National Electricity Market (NEM), and it is important that the implementation timeframe allows sufficient time to complete this work.
- The AEMC's proposal for transmission hedges to drive network investment has no precedent in other markets, is unworkable and should not be pursued further.
  - this third element is not required to realise the benefits from the other two elements of the reforms, and it puts at risk the efficient development of the transmission network;
- The Integrated System Plan (ISP) and regional planning processes should continue to be the central elements of transmission planning:
  - this will ensure that consumers pay as low a cost as possible for a reliable and secure system as the generation sector transforms and decarbonises.
- Separate from the planning process, the auction of transmission hedges (both short-term and long-term) could provide an additional source of funds to reduce consumers' Transmission Use of System Cost (TUOS) charges.
- The AEMC should consult separately on a range of options for facilitating Renewable Energy Zone (REZ) developments, including the government-supported funding approach being developed by the Energy Security Board.
- It is essential that the Coordination of Generation and Transmission Investment (COGATI) reforms represent a step toward any further, post-2025 changes to the wholesale market and transmission access arrangements arising from the Energy Security Board's (ESB) post-2025 blueprint process.
  - It is also important that transmission investments made over the next few years under the current (and evolving) regulatory regime are appropriately treated to maintain financeability and investor confidence.

Overview

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

Transmission members of Energy Networks Australia welcome the opportunity to comment on the AEMC's directions paper for the COGATI review, as well as for continuing participation on the technical working group established to progress these reforms.

Energy Networks Australia seeks to clarify whether the reforms at the transmission level are intended to be extended to the distribution network. If so, we note that the operation of the distribution system differs from the transmission system and therefore transposing the reforms should entail a separate consultation with increased clarity on the implications for distribution networks and their customers.

Energy Networks Australia supports generator access reform that promotes the long-term efficiency of both generation and transmission outcomes which will ultimately deliver benefits to consumers. The objective should be to ensure consumers pay as low a cost as possible for a reliable and secure system as the generation sector transforms and decarbonises. Reform must also result in an effective, practical access framework and meet essential power system requirements.

The directions paper proposes fundamental reforms to the arrangements by which:

» wholesale market prices are specified – by shifting to LMP for settling scheduled and semi-scheduled generation, and scheduled load (together 'scheduled energy');

» generators can manage the risk of constraints on their ability to dispatch energy to the market – by the introduction of financial transmission hedges which provide financially firm access; and

» the Australian Energy Market Operator (AEMO) and transmission network service providers (TNSPs) plan the network – through the introduction of a 'generator access standard' to which the networks must be planned.

The first two elements of the AEMC's proposals build on approaches which are mainstream practice in electricity markets internationally. Given this, there is a greater likelihood they can be implemented successfully in the NEM. However, there are still significant detailed design aspects of these elements that remain to be worked through and require further consideration. The timeframe set down by the AEMC raises the risk of an ill-developed and rushed implementation, with unintended consequences, during what is already a time of fundamental change in the sector. Energy Networks Australia therefore cautions against a rushed implementation of these elements and encourages the AEMC to undertake a process of more considered development to enable these key reforms to be introduced successfully.

AEMC 2019 COGATI directions paper, 2 August 2019

In contrast with the first two elements of the AEMC's proposed reforms, the third element of the proposals under which generators' purchase of transmission hedges would lead to an obligation on AEMO and TNSPs to plan and build the network to reflect the quantity of hedges sold, is not a feature of any other electricity market currently. Indeed, it is an approach that is now widely considered to be unworkable in practice.[1]

Energy Networks Australia is concerned that the potential contribution of transmission hedges in determining future investment has been overplayed by the AEMC and considers that the mechanism proposed is simply not feasible. Energy Networks Australia strongly suggests that the AEMC does not pursue this third element further, and instead focuses on further developing the LMP and transmission hedging elements of its proposals, as these elements have the potential to provide benefits independent of also pursuing the further third element.

Energy Networks Australia considers that the Integrated System Plan (ISP) process, which brings together the AEMO and TNSPs' planning expertise, together with TNSPs' regional planning activities, should continue to be central to the future development of the transmission network. This approach will ensure that consumers pay as low a cost as possible for a reliable and secure system as the generation sector transforms and decarbonises. Separately, the auctioning of transmission hedges (both short-term with respect to the existing network and long-term with respect to new investment identified by the planning processes) has the potential to provide an additional source of funds to reduce consumer TUOS charges.

Energy Networks Australia notes that the proposed reforms to access and planning, which are substantial even considered by themselves, are occurring as part of a broader reform process, and further potentially far-reaching changes arising from the ESB's post-2025 blueprint process. In this context, it is important the transmission access reforms represent a step toward any further, post-2025 changes to the wholesale market and transmission access arrangements.

It is also important that transmission investments made over the next few years under the current (and evolving) regulatory regime to progress implementation of the 2018 ISP and the 2020 ISP have appropriate regulatory transitional arrangements that maintain financeability and investor confidence.

[1] See for example, H Fraser, *Can FERC's standard market design work in large RTOs?*, in Electricity Journal, July 2002. The theoretical barriers to 'FTR-led' transmission investment (set out in this paper) that were recognised in the early 2000's, and the absence of any large-scale transmission investment being undertaken on this basis in practice in other markets which have FTRs, means that FTR-led investment has not been a 'live' issue under debate since this time.

Energy Networks Australia supports the introduction of LMP in concept (including dynamic marginal loss factors)

Energy Networks Australia supports the introduction of LMP in concept as a means of providing pricing signals to generators that better reflect the marginal cost of supplying electricity at their location in the network. However, further work is required in order to be confident that these arrangements can be successfully implemented in the NEM, and Energy Networks Australia cautions against a rushed implementation.

In relation to some of the design issues that remain to be addressed:

- The inclusion of dynamic marginal loss factors as part of the LMP design is a feature of all international markets that currently adopt LMP, and Energy Networks Australia urges the same approach to be adopted by the AEMC. The treatment of loss factors is integral to the design and introduction of LMP, and should not be treated as a separable issue;
- A first-best approach under which all supply sources including generation and storage (scheduled, semi-scheduled and non-scheduled) - as well as scheduled load - face LMP should be strongly preferred, if achievable, over arrangements under which some of these resources continue to receive the RRP for providing the same product. However, the implications for distribution network operation of such a change needs to be carefully considered;
  - If application of LMP to all generation and storage is not achievable, then the option proposed by the AEMC under which non-scheduled resources receive the RRP would appear to be the next most appropriate approach, albeit that there would be a number of issues to work through with its implementation.
  - Under this option, the RRP applied to non-scheduled resources (and to non-scheduled load) in a region should (as a first-best approach) be the MWh-weighted average LMP at each node in that region, although it may be necessary to consider second-best approaches.
- Energy Networks Australia does not support a staged approach to the introduction of LMP, under which locational prices are applied to progressively smaller regions, as this would increase and prolong the overall disruption experienced across the sector. However, it will be important for the introduction of LMP to be subject to thorough system tests and trials, ahead of 'go live'.

Energy Networks Australia endorses the potential contribution of transmission hedges as a risk management tool for generators

Transmission hedges can provide generators (and other market participants) with a mechanism to manage congestion-related price risks (achieve firmer access) for their output, and also provide a source of funds that can be used to reduce the TUOS charges payable by consumers.

This role for transmission hedges is consistent with the objectives for introducing transmission hedges (or Financial Transmission Rights (FTRs)) into many, best practice, wholesale electricity market designs around the world (with New Zealand being the closest and most similar example).

Energy Networks Australia considers that:

- short-term hedges relating to the existing transmission system should be issued by AEMO (in consultation with TNSPs), in its role as independent market operator;
- longer-term hedges arising as a result of new transmission investment (where that investment is identified under the strategic, integrated ISP and regional planning processes, as at present) should be issued by the relevant TNSP;
- in both cases hedges should be settled by AEMO as part of its market settlement function, and the TNSP would not be the counterparty to the hedging contract (and would not bear any risk as a consequence);
- hedges should generally be issued via an auction, so they are allocated to the party that values them the most and raise the most revenue:
  - the AEMC's proposed 'fair value' approach to pricing hedges is impractical and would result in economically inefficient outcomes; and
- revenue raised from the auctioning of hedges should be used to offset consumer TUOS charges.

Under this approach, the provision of transmission hedges would not drive transmission investment, but would still allow generators to achieve firm financial access, as well as providing an additional source of revenue to reduce consumer TUOS charges.

The Integrated System Plan (ISP) and regional planning should remain central to transmission network development

Energy Networks Australia considers that the ISP plays a fundamental role in identifying investments that address congestion and coordinating planning activities across the NEM. The ISP (which is prepared by AEMO and draws on and is supported by detailed regional planning undertaken by the TNSPs) is directly targeted at identifying least cost transmission investments that will minimise costs to the NEM as sources of generation change. It is important that access reform does not jeopardise or undermine the network investments that will be progressed through the current and future ISPs.

Information revealed through LMP (in particular price separation between nodes) and through demand for transmission hedges between particular nodes can be one source of data used to help inform network development, consistent with the approach adopted in New Zealand. Specifically, such information may have value in the development of the ISP and in regional planning processes to the extent that it helps substantiate expectations around network congestion (and therefore the 'identified need' for transmission investment), and the weight that should be given to future generation development scenarios. As such, it would be considered alongside other information as part of these planning processes.

Energy Networks Australia suggests an approach in this submission (see section 6) which could integrate the AEMC's proposals to introduce LMP and transmission hedges with the separate ISP and regional transmission network planning arrangements, and provide a source of funds from generators (and potentially other parties) to reduce consumers' TUOS charges.

The AEMC's proposal for transmission hedges to drive network investment is unworkable and should not be pursued further

The AEMC's proposed approach of combining pre-sold financial hedges with the imposition of a 'generator access standard' that AEMO and TNSPs would be required to plan the network to has no precedent in other markets. Academic research concluded nearly two decades ago that there are good reasons to think that an approach where transmission investment is driven by the sale of FTRs rather than strategic, integrated planning processes is unworkable,[2] and there are no markets elsewhere where major investment of the shared transmission investment has resulted from the sale of long-term hedges.[3]

Energy Networks Australia strongly considers that this element of the COGATI reforms should not be considered further. Instead, effort should be focused on the implementation of LMP and transmission hedging to provide generators with a risk management tool. These already represent substantive changes to the current arrangements which can be expected to provide many (if not all) of the benefits being sought by the AEMC, through improving wholesale market efficiency and improved signals for transmission and generation coordination. Moreover, there remain many elements of detail to be developed in these two proposed areas of the reform alone.

Any continued contemplation of the introduction of untested arrangements of this nature should not be pursued without a compelling assessment of the costs and benefits, as well as the risks of unintended consequences. It is not apparent that such an assessment is currently planned by the AEMC.

The objective of the reforms should be to ensure consumers pay as low a cost as possible for a reliable and secure system as the generation sector transforms and decarbonises. It does not follow that simply reducing the direct investment risk borne by consumers will deliver this objective. For example, any increased investment risk on TNSPs must be matched by higher required rates of return. The AEMC does not appear to consider how this might work and if this is a better deal for consumers.

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[2] See for example, H Fraser, *Can FERC's standard market design work in large RTOs?*, in Electricity Journal, July 2002.

[3] In the US there are a very limited number of cases where radial transmission investment has been funded by the sale of FTRs, but this has been in the context of merchant transmission links, rather than regulated TNSPs.

REZ development

The discussion paper sets out two options for assisting the development of REZs, as a transitional measure ahead of the introduction of LMP and transmission hedges.

Energy Networks Australia suggests that the approach to REZs be considered via a more focused consultation process, rather than as an 'add-on' to the broader access reforms. The principles supporting arrangements for REZ development should include:

- that the arrangements can sit alongside the broader COGATI reforms, and be applied on an enduring basis as the transmission network develops; and
- TNSPs should not be exposed to risks outside of their control as part of the COGATI arrangements and should receive adequate compensation for the risks borne.

Energy Networks Australia considers that a range of development options for REZs should be considered, and that the options need not be mutually exclusive. This reflects that REZ development will not be a 'one-size-fits-all' matter. The mechanisms considered for REZ development should include:

- the government-supported funding approach being developed by the Energy Security Board;
- the exploration of an 'open-season' type process as indicated under AEMC's option one; and
- the use of some form of down-payment or transmission bond, so that generators (or other parties) can back their intentions by putting up financial commitments, some portion of which may then be refunded once those generators have connected to the developed REZ.

Energy Networks Australia considers that flexibility in development pathways for REZs is appropriate, reflecting that different parties are expected to benefit from REZs, and that this may vary between specific REZs. The distinction between shared network augmentation and network extension to enable REZ development also needs to be recognised.

Although Energy Networks Australia supports consideration of flexible funding arrangements, we have a number of reservations regarding the 'PIAC model',[4] including that it appears to set up a fundamental disconnect between the party bearing the risk (the TNSP) and the parties who determine the extent of that risk (AEMO) and the compensation for bearing that risk (the Australian Energy Regulator (AER)). This can be expected to lead to a very real risk of the investment not proceeding.

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[4] As outlined in the directions paper, and in the paper provided by PIAC to the Technical Working Group, *PIAC's framework for centralised supply investment and model for generation-leading transmission investments*, May 2019

1 Introduction

Transmission members of Electricity Networks Australia welcome the opportunity to respond to the AEMC's directions paper on access reform, in the context of the wider COGATI reforms.

The directions paper proposes fundamental reforms to the arrangements by which:

- wholesale market prices are specified – by shifting to LMP for settling scheduled and semi-scheduled generation, and scheduled load (together 'scheduled energy');
- generators can manage the risk of constraints on their ability to dispatch energy to the market – by the introduction of financial transmission hedges which provide financially firm access; and
- AEMO and TNSPs plan the network – through the introduction of a 'generator access standard' to which the networks must be planned.

The principal stated objectives of these far reaching reforms are:

- to provide price signals to generators that more accurately represent the marginal cost of supplying electricity at their location in the network, thereby improving locational pricing signals and the coordination of new transmission and generation investment;
- to improve the financial risk management options for market participants, to address current generator uncertainty around network access; and
- to increase the influence and commitment of generators in the transmission planning process, thereby reducing the risk of 'roads to nowhere', with generators also contributing a portion of the cost of providing the transmission network rather than transmission costs being directly borne only by consumers.

This submission sets out Energy Networks Australia's responses in relation to each of the three major elements of the AEMC's proposed reforms.

In summary, whilst Energy Networks Australia supports in concept the first two elements of the reforms (the introduction of LMP and financial hedges), our transmission members do not support the third element under which the sale of hedges would drive transmission planning and investment.

Energy Networks Australia does not consider the AEMC's proposals in this area to be workable. We urge the AEMC to instead focus on progressing the first two elements only, whilst retaining the centrality of the ISP and regional transmission planning processes in determining the efficient pathway for future transmission development, at the lowest cost to consumers.

This response focuses on the fundamental rationale and approach underpinning each of the three elements of the AEMC's proposed reforms, and the extent to which they do (or do not) represent a consistent, practical and cohesive package and fit with the wider reform agenda being pursued by the ESB (including the 'Actionable ISP' developments). Energy Networks Australia considers that it is important to get alignment on the overall direction of each of the proposed elements, before diving further into some of the issues of detail canvassed in the directions paper, which in some cases reflect very detailed design issues.

Notwithstanding, this submission offers views in response to some of the more detailed questions posed in the directions paper, where they most closely relate to issues impacting transmission.

2 Reforms should build on proven approaches and be consistent with the central role of the ISP and regional planning processes

Energy Networks Australia understands the AEMC's essential proposition that fundamental reforms to transmission access arrangements are required, in light of the transition occurring in the energy sector and the need for transmission investment to facilitate efficient, reliable electricity supply from new generation sources.

Energy Networks Australia supports in concept the AEMC's proposed reforms to the wholesale market pricing arrangements to introduce LMP, and the introduction of financial hedges as a risk management tool to improve generator certainty around market access. These elements of the AEMC's proposals build on approaches which are mainstream practice and have been proven in other electricity markets internationally. This increases the likelihood of their successful implementation in the NEM.

We provide some responses in the relevant sections below on the specific issues raised by the AEMC for consultation on these two elements. Energy Networks Australia notes that there are still significant detailed design aspects that remain to be worked through in relation to these elements. The timeframes set down by the AEMC are beyond optimistic and raise the risk of an ill-developed and rushed implementation, with unintended consequences, during what is already a time of fundamental change in the sector. Energy Networks Australia therefore urges the AEMC to identify and adopt a more realistic timeframe that provides a greater likelihood of successful implementation of these key elements of the reforms.

In addition, Energy Networks Australia has significant concerns in relation to the practicality of the network planning elements of the AEMC's proposals, and how they integrate with the ESB-initiated 'actionable ISP' reforms:

» Although an apparently strong motivation for the reforms is to improve the 'influence' of generators in transmission planning and investment decision-making, Energy Networks Australia considers that the approach put forward by the AEMC overestimates what can be achieved in practice and will be unworkable;

- The AEMC's proposed approach of combining pre-sold financial hedges with the imposition of a 'generator access standard' that AEMO and TNSPs would be required to plan the network to[5] has no precedent in other markets, and previous academic research has identified reasons why such an approach is unlikely to work in practice.[6]
- Energy Networks Australia considers that the introduction of untested arrangements of this nature should not be contemplated and, moreover, are not required in order to realise the benefits of introducing improved locational pricing and hedging to provide firm financial access.
- Any continued contemplation of the introduction of untested arrangements of this nature should not be pursued without a compelling assessment of the costs and benefits, as well as the risks of unintended consequences. Such an assessment does not appear to be currently planned by the AEMC.
  - A pre-requisite for such an assessment would be a substantially more detailed specification of the AEMC's proposed model, covering how the principles set out would be converted to actual market or administrative mechanisms;
- Energy Networks Australia suggests an alternative approach in section 6 of this submission which would better integrate the AEMC's proposals to introduce LMP and transmission hedges with the ISP and regional transmission network planning arrangements, and would provide an additional source of funds from generators (and potentially other parties) to reduce consumers' TUOS charges.

Finally, Energy Networks Australia notes that the proposed reforms to access and planning, which are substantial even considered by themselves, are occurring as part of a broader reform process, and further potentially far-reaching changes arising from the ESB's post-2025 blueprint process. In this context, it is important the transmission access reforms represent a step toward any further, post-2025 changes to the wholesale market and transmission access arrangements. It is also important that transmission investments made over the next few years under the current (and evolving) regulatory regime to progress implementation of the 2018 ISP and the 2020 ISP have appropriate regulatory transitional arrangements that maintain financeability and investor confidence.

3 LMP can provide improved price signals

Generators presently receive the RRP for each MWh of electricity dispatched, regardless of where they locate in a region. The RRP paid to each generator is

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[5] AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p 74.

[6] See for example, H Fraser, *Can FERC's standard market design work in large RTOs?*, in Electricity Journal, July 2002.

adjusted for its annually updated marginal loss factor (MLF), being the estimated marginal losses for delivering power from that location to the regional reference node.

The AEMC is proposing to change these arrangements so that generators who provide scheduled energy receive a dynamic 'locational marginal price' (LMP) that more accurately represents the marginal cost of supplying electricity at their location in the network.

The directions paper notes the relationship between LMP and the current approach to applying MLFs but the AEMC raises as a separate issue for consultation on how MLFs can or should be adjusted to fit with its proposed pricing reforms. Energy Networks Australia does not consider that this issue is separable, and notes that LMP has a specific meaning in the jurisdictions in which it has been implemented, that involves the marginal cost of losses being included in the market prices, and those marginal losses being applied both on a dynamic basis (ie, real losses, recalculated in each trading period) and on a locational basis (ie, calculated for each transmission pricing node). That is, LMP includes the marginal cost of losses and the marginal of congestion (if any) at each location in each time period.

Energy Networks Australia supports the introduction of LMP (reflecting dynamic marginal loss factors) in concept as a means of improving the efficiency of wholesale market outcomes and also providing pricing signals to generators that better reflect the marginal cost of supplying electricity at their location in the network.

The AEMC states in the directions paper: "[t]he investor should seek a location for a power station, which minimises the combination of its operating and establishment costs and the cost of transmission." [7]

Energy Networks Australia considers that this is a worthy goal and that the element of the AEMC's proposed reform that goes the furthest to meeting this goal is the introduction of LMP alone, since LMP combines the relevant price signals for generation and transmission into a single price signal to generators at each location.

Notwithstanding this conceptual support, Energy Networks Australia notes that there remains substantial detail to work through in order to successfully implement LMP. Energy Networks Australia supports retaining the regional market model – at least in the near-term – and therefore the continuing existence of the existing Regional Reference Nodes and the concept of Regional Reference Prices, to avoid significant disruption in the current financial hedging markets.

In response to the specific issues raised for consultation in the directions paper:

» Energy Networks Australia considers that the 'first-best' approach would be the application of LMP across all supply sources including generation and storage (scheduled, semi-scheduled and non-scheduled) as well as scheduled load, although recognises that challenges with updating the NEM dispatch engine

[7] AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p iii.

(NEMDE) and potential implications for distribution networks may require a more pragmatic approach to be adopted;

  - If this is not achievable, then the option proposed by the AEMC under which non-scheduled resources receive the RRP would appear to be the next most appropriate approach, albeit that there would be a number of issues to work through with its implementation.

- Energy Networks Australia recommends that the RRP for a region be calculated based on:
  - the MWh-weighted average LMP of nodes in that region, as a first-best solution. Energy Networks Australia notes that the calculation of LMP on a full nodal basis across all generation, storage and load (both scheduled and non-scheduled at transmission level) could be undertaken using separate software, not linked to the NEMDE, in order to implement this approach;
  - if it is not practical to include non-scheduled load points in the full nodal calculation of the RRP, then as a second-best solution non-scheduled loads should settle at an RRP that is calculated as at present, as the marginal value of the regional energy balance constraint; and
  - if it is not practical to include non-scheduled generation points in the LMP calculation, then as a third best solution where RRP is applied to non-scheduled generation it should also be calculated as the marginal value of the regional energy balance constraint.
- Energy Networks Australia strongly supports the development of dynamic marginal loss factors and the integration of these within the LMP and transmission hedges framework, consistent with the way LMP is applied internationally; and
- Energy Networks Australia does not support a staged approach to the introduction of LMP and transmission hedges under which locational prices are applied to gradually smaller and smaller zones, on the basis that this would increase the overall disruption experienced across the sector.

These issues are expanded on below.

3.1 Scope of dynamic regional pricing

The AEMC asks a number of questions in relation to the scope of LMP.[8]

The AEMC's proposal is that:

- all scheduled and semi-scheduled market participants (ie, generation, load and storage) would face their LMP;
- all non-scheduled participants – both load and generation – would face the RRP; and
- parties would not otherwise be able to opt in or out of facing an LMP.

[8] Question 2, AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p 59.

The AEMC's proposal that non-scheduled load faces the RRP is consistent with the operation of LMP in other markets. It is quite normal internationally for LMP to apply on a nodal basis for generators and on either a nodal or zonal basis for load.

In contrast, the proposal that non-scheduled generation also continues to face the RRP is not consistent with the approach adopted in other markets. The AEMC's proposal is strongly influenced by the existing configuration of the NEMDE, which does not currently provide for non-scheduled load or generation to be settled at local prices. In light of this constraint, the AEMC proposes that resources not scheduled through the NEMDE be settled at the RRP.

The first-best solution would be to expand the NEMDE so that all generators (and storage) are captured and the LMP can be calculated in all cases, or to use alternative software to calculate LMP. Energy Networks Australia recognises that such a revision to the NEMDE, alongside the changes to the NEMDE already being made to accommodate five-minute settlement and the revisions required to also facilitate dynamic marginal loss factors (see section 3.3) would be a substantive exercise. However, experience elsewhere strongly suggests that inflexibility in established IT systems should not be allowed to dictate market design decisions. It is better to 'get it right' than to create second-best, complex, and economically inconsistent pricing arrangements. Notwithstanding, the implications for distribution network operation of such a change needs to be carefully considered.

Energy Networks Australia recognises that the AEMC's proposed option may be a pragmatic approach to addressing the current limitations with using the NEMDE to establish the LMP for non-scheduled generation. However, it is inevitably a second-best solution that would bring with it a number of issues to be addressed, namely:

» older intermittent generators that are classified as non-scheduled would face a different price (the RRP) to newer generators (who are classified as semi-scheduled and so who would face the LMP), even though they are providing exactly the same product, and even where the plants may be located side-by-side. There is no efficiency rationale for this; and
» generators below the current 30 MW threshold would be classified as non-scheduled and face a different price to generators above this size (who are classified as scheduled or semi-scheduled), which may lead to gaming incentives in deciding on the size of plant. [9]

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[9] Energy Networks Australia notes that the AEMC has a pending rule to consider changing the 30MW generator registration threshold to 5MW. AEMC has also recently issued a Draft Determination on the wholesale demand response mechanism to enable the option for large customers on the LV networks with a demand response to be scheduled and included in NEMDE. The implications on global settlement in 2022, aggregated demand response and small customer VPP eventually need to be more fully considered. Ideally a level playing field would be considered where scheduled generation and load is indifferent to connection at the transmission or distribution network. Some distribution networks continue to experience unprecedented growth in the size and volume of large-scale embedded generation seeking to connect to their networks. It is therefore critical to ensure that the outcomes of this process do

3.2 Options for aggregating LMPs to derive the RRP

The directions paper canvasses various, detailed options for aggregating LMPs to define the RRP or some other aggregate price for settling non-scheduled load and non-scheduled generation and storage. [10]

As highlighted above, further consideration should be given to achieving arrangements that allow all generators and storage (scheduled, semi-scheduled and non-scheduled) to face LMPs, rather than needing to derive an RRP to apply to these generators. Notwithstanding this view, Energy Networks Australia recognises that non-scheduled load is likely to continue to face the RRP.

The most important principles to consider in relation to deriving the RRP are to achieve economically efficient prices and design consistency so that the arrangements deliver revenue adequacy for transmission hedges. These principles mean that the options for deriving the RRP should be evaluated by reference to the need to define an RRP that is consistent with the basis on which the whole market is being dispatched and priced.

In practical terms, the MWh-weighted average LMP at each node within a region (or aggregate pricing zone) best reflects the average marginal cost in that zone and is the only measure that will ensure revenue adequacy within the wholesale market and be internally consistent with the proposed system of transmission hedges.

Energy Networks Australia recommends that the RRP for a region be calculated based on:

- the MWh-weighted average LMP of nodes in that region (or aggregate pricing zone), as a first-best solution. In particular, at transmission level:
  - non-scheduled loads settle at an RRP that is calculated as the non-scheduled-load-weighted LMP across all non-scheduled loads in that region;
  - where non-scheduled generators face the RRP, this is calculated as the weighted average LMP of non-scheduled generators (ie, weighted by generator production of all non-scheduled generators) in the region concerned.

  Energy Networks Australia notes that the calculation of LMP on a full nodal basis across all generation, storage and load (both scheduled and non-scheduled at transmission level) could be done using separate software, not linked to the NEMDE, in order to implement this approach;
- if it is not practical to include non-scheduled load points in the full nodal calculation of the RRP, then as a second-best solution, non-scheduled loads should settle at an RRP that is calculated as at present, as the marginal value of the regional energy balance constraint; and
- if it is not practical to include non-scheduled generation points in the LMP calculation, then as a third best solution the RRP applied to non-scheduled

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not drive perverse outcomes for distribution networks. This will require further consideration once the transmission network implications are better defined.

[10] Question 3, AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p 60.

generation should also be calculated as the marginal value of the regional energy balance constraint.

3.3 Treatment of losses

The directions paper seeks stakeholder input on how losses should be treated within the dynamic regional pricing model.[11]

Energy Networks Australia strongly supports the development of dynamic marginal loss factors and the integration of these within the LMP and transmission hedges framework. This is consistent with Energy Networks Australia's position in response to the AEMC's recent consultation paper on transmission loss factors, which expressed a preference for a move to dynamic marginal loss factors as part of either the five-minute settlement project or the COGATI proposals. International best practice does not modify the settlement quantity by a loss factor, but rather modifies the LMP itself. The objectives of the proposed introduction of LMPs and transmission hedges would undoubtedly be assisted if dynamic marginal loss factors could be integrated into the design formulation.

Trying to integrate the existing MLF arrangements alongside LMP is likely to lead to complexity and unintended consequences that risk undermining the objectives of the reforms. Although Energy Networks Australia recognises the transitional challenges of amending the NEMDE to accommodate dynamic marginal loss factors, we consider that this is an integral feature of adopting the LMP approach. All LMP markets internationally treat marginal losses as being: (i) included in the price; (ii) dynamic; and (iii) nodal.

More generally, the co-dependence of the treatment of losses and the introduction of LMP and transmission hedges raises important sequencing issues. The AEMC's proposals are effectively trying to design LMP for transmission hedging without all of the underlying principles for LMP design (such as the treatment of losses) being settled and/or aligned with other changes currently being considered (eg, the current Rule change proposal on transmission losses). The focus should be to develop a holistic, consistent and workable framework for LMP and transmission hedges, and this needs to incorporate an updated approach to the treatment of loss factors. Energy Networks Australia notes that achieving this outcome will require longer than the AEMC has currently allowed for under its timeframe.

Consistent with this there is also a need for clarity about the technical and practical aspects with implementing LMP and dynamic marginal loss factors in the NEMDE. At the MLF webinar, AEMO indicated it would take two years for the implementation of dynamic marginal loss factors alone. If LMP is added to the implementation program, the risks, costs and implementation timeframes must be addressed.

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[11] Question 4, AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p 60.

3.4 Application of a market price cap to LMPs

The directions paper raises the issue of whether LMPs should be subject to the market price cap arrangements that apply at the RRP, in order to mitigate potential local market power concerns.

Energy Networks Australia considers that the most important principle to apply is internal consistency between LMPs and RRPs, so that the financial integrity of both wholesale market settlement and transmission hedges is retained. LMPs could be capped at some level (such as the existing market price cap) and then the RRP (which is calculated as the weighted average of LMPs) would by definition be capped also.

More generally, Energy Networks Australia notes that market power concerns in the context of a move to LMP are often over-stated, particularly once account is taken of the ability of generators with market power to find ways to exploit that power just as forcefully under regional price settlement models.

3.5 Allocation of settlement residues

The AEMC's directions paper asks stakeholders a specific set of questions in relation to how transmission hedge settlement residues should best be allocated.[12]

The AEMC's focus in asking these questions is on settlement residues that arise when, in any settlement period, there is a difference between: a) the level of funds available to pay holders of transmission hedges; and b) the level of financial obligation to those transmission hedge holders. We note that this is a separate issue to the question of how the proceeds from the sale of transmission hedges should be treated.

Energy Network Australia's view is that consideration should be given to a more efficient use of excess settlement residues more generally, through optimising how they are ultimately returned to consumers. Energy Networks Australia's recent submission on the AEMC's consultation paper on transmission loss factors highlighted the volatility of settlements residues, and the impact that this has on transmission charges, where settlement residues are returned to consumers via being used to offset TUOS charges.

In that separate submission Energy Networks Australia proposed the development of a distribution process for settlements residues which could be integrated into the market settlements process performed by AEMO and returned to consumers. This would allow for more stable transmission charges, as transmission charges would not then fluctuate depending on the level of settlement residues.

Energy Networks Australia suggests that any settlement residues associated with transmission hedges be treated in the same way.

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[12] Question 1, AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p 51.

3.6 'One-step' or staged approach to the introduction of LMP and transmission hedges

The AEMC asks for stakeholder comment on whether the move to LMP and transmission hedges should be staged through its application to progressively smaller and smaller regions, or applied on a fully nodal basis from the start.

Energy Networks Australia expects that a staged approach to introducing LMP through the progressive move to smaller and smaller regions would lead to additional and unnecessary complexity, with little apparent gain. We also note the interaction between changes to the wholesale pricing arrangements and the existing price hedging arrangements in the sector. A staged approach to implementation of LMP and transmission hedging would necessitate additional disruptions to these contractual arrangements.

Energy Networks Australia therefore considers that a 'one-step' implementation process is preferable, with the number of nodes being determined by the existing constraints reflected in the NEMDE. Although this will be a major reform, disruption will occur even under an approach where the number of pricing nodes is increased incrementally, and so a 'big bang' approach appears to be preferable.

Notwithstanding the above, it will be important for the introduction of LMP to be subject to thorough systems tests and trials, ahead of 'go live'.

4 Transmission hedges have value in providing firm financial access

Energy Networks Australia supports in concept the introduction of transmission hedges to provide firm financial access, on the basis that they can be expected to improve the efficiency of the wholesale market and so benefit consumers. Such instruments would:

- provide generators (and other market participants, as they wish) with a mechanism to manage congestion-related price risks (achieve firmer access) for their output; and
- provide a financial contribution that can be used to reduce the TUOS charges payable by consumers.

Transmission hedges have the potential to play a key role as a risk management tool for generators (as well as potentially other parties). This is consistent with the objectives for the introduction of transmission hedges (also called financial transmission rights (FTRs)) into many, best practice, wholesale electricity market designs around the world (with New Zealand being perhaps the closest and most similar example). Energy Networks Australia fully endorses the potential contribution of transmission hedges in this function, although again notes that there are a number of detailed design issues to be worked through in order to achieve successful implementation in the NEM.

ENA sees two distinct mechanisms whereby transmission hedges can be procured by generators. These two mechanisms reflect the already well-established roles for AEMO as the market and system operator and TNSPs as transmission network investment decision-makers:

- short-term hedges backed by the existing network capacity should be issued by AEMO (based on the node to node limits and limit equations provided by TNSPs), in its role as independent market operator.
  - AEMO is an independent party and is best placed (in consultation with TNSPs) to determine the quantity of hedges that can be made available between different nodes in the transmission system, after allowing for any long term hedges already created (see below), to be consistent with the NEMDE;
  - AEMO is also the party that collects the congestion rents (ie, differences between LMP and RRP) from which payments to transmission hedge holders are funded;
  - these hedges would generally be in the order of up to three or so years;
- longer-term hedges backed by the development of new transmission investment could be issued by the relevant TNSP:
  - these hedges would be issued in parallel to the planning process and at the point where the planning process has identified the expected optimal transmission investment (see the proposed approach in section 6);
  - importantly, these long-term hedges would not drive the planning process (in contrast to the AEMC's proposal – see below), with investments in the shared network continuing to be determined through the ISP and regional planning processes;
  - these longer-term hedges would be offered for periods in the order of over ten years.
- hedges (both short and long-term) should generally be issued via an auction, so that they are allocated to the party that values them the most and priced based on the value determined by those purchasing the hedges. The use of auctions for transmission hedges is common internationally and is a sensible way to price and allocate a scarce resource;
- the revenue derived from the auction of hedges (both short and long-term) should be used to reduce the TUOS charges faced by consumers.
  - Auctioning-off hedges in advance provides greater certainty in terms of the impact on TUOS – compared with the short-term variability on settlements residues which is driven by spot price variability; and
- in both cases hedges should be settled by AEMO as part of its market settlement function, and the TNSP would not be the counterparty to the hedging contract (and would not bear any risk as a consequence).

Section 6 provides more detail on how the process for auctioning long-term hedges would operate alongside the ISP and regional planning processes.

5 The use of transmission hedges as a capex decision-making tool is unworkable

Energy Networks Australia agrees that access reform and the ISP processes should be integrated.[13] However, we do not agree with the AEMC's assessment in the directions paper of how this can be achieved.

The directions paper suggests that the quantity of transmission hedges sold will 'inform' the transmission planning and investment decisions that are then made, both by AEMO and TNSPs in developing the ISP as well as also by individual TNSPs as part of their regional planning activities.[14] Energy Networks Australia considers that the potential contribution of transmission hedges in determining future investment has been overstated by the AEMC in the context of the proposed COGATI reforms and that the mechanism proposed is not feasible.

5.1 LMP and interest in transmission hedges can provide an additional source of information for network planning

Information revealed through LMP (in particular price separation between nodes) and through generators' demand for transmission hedges between particular nodes, may be an additional, useful source of data to inform network planning. This is more consistent with the earlier suggestion by the AEMC (under the 'staged implementation' proposal in the AEMC's March 2019 Consultation Paper) that LMP and transmission hedges could be used to inform planning decisions.

In particular, AEMO and the TNSPs could use this information in the preparation of the ISP as an indicator to further substantiate where network constraints are occurring and the value of relieving those constraints. Similarly, TNSPs could also draw on this information as part of regional planning activities, and in supporting the 'identified need' in RIT-T assessments. Currently, information on constraints is contained in the NEMDE but is arguably less transparent to the market than if it were reflected in published LMP price separation. In particular, the cost of congestion is problematic to discern due to the existing incentives for disorderly bidding in the presence of network constraints.

New generators' willingness to purchase transmission hedges (in particular long-term hedges) may also justify placing a greater weight on ISP and RIT-T scenarios that reflect forecast generation at those locations, to the extent that it provides an additional indication of the likelihood of that generation occurring. The purchase of

[13] Question 6, AEMC, COGATI – Access reform, Directions paper, 27 June 2019, p 75.

[14] AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p 74

transmission hedges would be an additional piece of information, that would be taken into account by AEMO and the TNSPs as part of the existing planning processes, alongside other information.

The use of LMP (in particular) and transmission hedge information in this way as an additional source of data to 'inform' network planning is consistent with the approach adopted in New Zealand. However, importantly, the information derived from the sale of hedges does not drive planning decisions nor lead to an obligation on TNSPs. Hedges would only be offered once the planning processes had identified new transmission investment as likely to provide an overall net benefit to the NEM (see section 6).

5.2 Transmission hedges cannot drive transmission investment

The AEMC appears to be overreaching in proposing a role for transmission hedges in driving transmission investment. Put simply, the AEMC's proposal is that TNSPs will sell hedges, and then both AEMO and TNSPs will face a primary obligation (the 'generator access standard') to plan and build the transmission network to reflect the quantity of hedges sold.

The AEMC's discussion in the directions paper reveals unrealistic expectations as to the extent to which generators' purchases of transmission hedges can either:

- 'directly influence'[15] transmission planning decisions in a material way; or
- contribute sufficiently to the costs of transmission services so that the basis upon which investment in new transmission capacity is decided and financed will change substantively from current practice.

Energy Networks Australia urges the AEMC to review the realism of these expectations, both in concept and in the sense of their 'back to front' perception of the ISP-centred transmission planning and investment decision-making processes that are now in place, and which are expected to remain at the core of the network planning arrangements under the 'actionable ISP' model.

There is no electricity market in the world where transmission hedges are used as a capital expenditure decision-making tool– whether for the existing shared network or major increments in capacity. Arrangements of this type were thought to hold great promise when FTRs were first developed in the 1990s but in the intervening years has not been demonstrated – in both academic literature and the absence of any implemented arrangements elsewhere – to be workable.

At a conceptual level, the idea that the sale of hedges would be capable of driving transmission investment decision overlooks the fact that:

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[15] AEMC, *COGATI – Access reform, Directions paper*, 27 June 2019, p 43

» the value of hedges in the eyes of a generator will be strongly affected by how much transmission is to be built – so that generator demand for hedges will not be independent of TNSP capacity decisions;

» yet, the value of hedges will itself affect the extent of their take up;

» in any case, once built to an efficient scale, new transmission assets generally either eliminate or substantially reduce the risk of congestion so that, post-build, hedges often have little market value; and

» in order to underpin new transmission investment, generator proponents would need to purchase hedges substantially ahead of their investment in generation and for a duration that was consistent with the long-lived nature of those assets.

In relation to this last point, although the purchase of transmission hedges by generators is a centrepiece of the AEMC's proposed reforms, it is not clear from the directions paper:

» who is the counterparty offering the hedging contracts;

» the point in the planning process at which such hedges would be offered and commitments to purchase them be made; or

» whether such hedges would be of sufficient duration to be capable of influencing a TNSP's decision to invest in 50 year plus assets.

The model proposed by the AEMC requires generators to purchase hedges many years out from when the generator will be able to operate, due to the lead-time required to complete the ISP planning process, the subsequent RIT-T regulatory approval processes and then the eventual transmission investment approval and construction process. In order to be reflected in the generator access standard with any certainty, the generator would need to purchase the hedges at least at the RIT-T stage, if not the earlier ISP stage (for transmission investments included in the ISP). The requirement to purchase hedges in advance of potential projects is either likely to be impractical or will favour larger generators. Alternatively, if the AEMC's proposal is based on AEMO and the TNSPs forecasting future generator demand for hedges at the planning stages, then it does not appear to offer any greater certainty that the transmission capacity will be used by generators than under the current forecasting arrangements.

Energy Networks Australia urges the AEMC to focus its future work program on arrangements by which the introduction of LMP and the potential sale of transmission hedges can helpfully inform the ISP and regional transmission planning processes and contribute to offsetting consumer TUOS charges, through working together with the current planning arrangements. This is discussed further in Section 6.

Energy Networks Australia considers that the proposals are likely to flounder if they are held to the standard implied by the 'sell hedges and build capacity to meet the obligations implied' view of the world described in the directions paper.

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5.3 Proposals for 'fair value' pricing are problematic

The AEMC has asked for stakeholder comment on its proposed 'fair value' approach to pricing transmission hedges, either outright or through adopting 'fair value' as the reserve price in a model where transmission hedges are auctioned. [16]

Energy Networks Australia understands that the 'fair price' would be based on the forecast, long run differentials between the RRP and LMP. Although different to the LRIC model that was evaluated and ultimately abandoned under the previous Optional Firm Access reform (the fair value approach doesn't try to capture the explicit marginal costs of transmission), the fair value approach shares many of same shortcomings.

Basing prices on long-term simulations of energy market locational prices would be impractical and economically inefficient for the simple reason that there is no way of accurately assessing and forecasting the likelihood, location and impacts of transmission security/stability constraints. Attempting to undertake such forecasts inevitably leads back to a strategic, integrated planning approach in which assumptions about future generation and transmission investment would still need to be made in order to forecast prices 50 or so years in the future.

Energy Networks Australia 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.

Inaccurate pricing risks creating winners and losers when reality differs from that modelled. This cannot ultimately be in customers' best interests. Differences between actual transmission investment costs and modelled costs reflected in transmission hedge pricing would presumably need to be recovered from consumers. This is likely to be particularly the case in the longer term. International experience demonstrates that there are likely to be limited cases in which market participants are willing to enter into a transmission hedge contract for a period anywhere near approaching the life of a transmission asset, or even the period over which the bulk of its debt was amortised. Even the AEMC notes in its directions paper that generator contributions can only provide partial funding of transmission investment.

Ultimately, the AEMC's 'fair value' pricing concept is linked to its proposals for transmission hedges to determine transmission investment. Where transmission

[16] Question 9, AEMC, COGATI – Access reform, Directions paper, 27 June 2019, p 79. Although Question 9 refers to the use of fair value pricing in the context of determining the 'product price', the AEMC also raises the prospect of transmission hedges being auctioned (Question 8, p. 77) and we understand that in this context the AEMC is considering applying the 'fair value' price as a reserve price in any auction.

hedges are instead used as a financial risk management tool, the pricing of available hedges would be more appropriately done via an auction (as noted in section 4), and there would be no need to impose a reserve price based on 'fair value', as issuing of a transmission hedge would not be a determining factor for transmission investment.

5.4 Proposals for an incentive scheme on TNSPs

The AEMC's proposals for an incentive scheme to be applied to TNSPs is predicated on the invalid assumption that the efficient level of network investment will be consistent with the quantity of hedges sold. It is not clear how an incentive scheme built on this premise could be efficient.

A relevant example is the use of system protection schemes in Tasmania. TasNetworks operates several of these schemes which are used to protect on-island generation and transmission from off-island contingencies such as the loss of, or temporary derating, of Basslink. Although these events would almost certainly see LMP pricing impacts with various generators constrained on and off to meet system security concerns, it would seem highly inequitable that TNSPs would be penalised for not meeting their transmission hedging obligations as a result. In order to avoid this, the hedging volumes would need to be set very conservatively, which would drive a further wedge between the value obtained from the sale of transmission hedges and the cost (and value) of the underlying transmission assets.

Energy Networks Australia notes that TNSPs are already subject to an incentive scheme under the Market Impact Component (MIC) of the Service Target Performance Incentive Scheme (STPIS). Energy Networks Australia considers that consideration of changes to the MIC to reflect the transmission service measures under the proposed LMP and financial hedging arrangements should be the focus of the AEMC's consideration of appropriate incentive arrangements.

6 Integration of transmission hedges with ISP and regional transmission planning

Although Energy Networks Australia considers that the AEMC's proposals in the directions paper represent an overreach in terms of the role that transmission hedges could play in influencing transmission planning outcomes, the ability for generators (and potentially other parties) to purchase long-term hedges could provide an additional source of revenue to be used to partially fund new investment and to reduce the TUOS charges consumers would otherwise face.[17]

[17] As noted earlier in this submission, the sale of short-term hedges is also a potential source of revenue that could be used to reduce consumer TUOS charges. The focus of this section is on the potential funding contribution that could be obtained from the sale of longer-term hedges, and how the process for the sale of such hedges could operate alongside the ISP and regional

Arrangements by which such a process could operate could be along the following lines:

» the ISP would inform priorities for investment in the shared transmission network that would take account of (expected) generation developments and draw on a range of information sources as to the nature and extent of existing network congestion, including LMP price signals and, potentially, transmission hedge information;
» TNSPs would conduct their RIT-T evaluations on each relevant transmission investment;
» In parallel to the RIT-T process, the relevant TNSP would conduct a separate process to determine generator interest in acquiring long-term hedges in relation to the additional transmission capacity associated with the new investment:
  - generators (and other parties) could be invited to make some form of down-payment or 'bid' for the subsequent right to secure long-term transmission hedges across the additional capacity, once it was built;
  - such bids or down-payments would be refundable if the relevant transmission capacity was not built whereas, if the transmission investment did ultimately pass the RIT-T and proceed, those down payments would establish a first right to acquire the relevant long-term transmission hedges, in competition (through auction) with others that had also made down-payments (with the down-payment being used as a credit for any sum subsequently offered); and
  - generators (or other parties) having bought such first rights to participate in a transmission hedges auction would be permitted to trade those rights prior to the auction;
» Importantly, the receipt of such down-payments or bids would not drive the RIT-T evaluation, but their existence would reveal generators' preparedness to fund transmission investment in return for firmer access to the RRP – preferably over the long-term - and would therefore allow greater confidence that the investment would not be a 'road to nowhere'; and
» Where it satisfies the RIT-T, the investment would proceed as part of the regulated shared network, with the proceeds of the auction being used to offset the TUOS charges consumers face.

Such an arrangement would place the proceeds from transmission hedges as a supplementary form of transmission financing, used to reduce consumers' TUOS payments, but would not form a financial consideration on which the planning process could or should seek to rely on.

Energy Networks Australia recognises that there remain issues to be overcome under this proposed approach, common to other potential models where generators

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planning processes (where the latter are the processes that are determining the appropriate investment).

contribute to the cost of new transmission investment. In particular, the incentives for parties to commit funds ahead of time will depend on their expectations of the value of the future transmission hedges, which will depend on the expected scale of the transmission investment. In addition, detailed allocation rules would need to be developed to recognise issues such as loop flows. However, the approach outlined above does not require generator contributions as a pre-condition for the investment to proceed, but instead allows the potential value of achieving firm future access to be realised through the sale of hedges and used to offset the investment costs faced by consumers, where market participants deem that value to exist.

7 Integration of renewable energy zones

Finally, the directions paper also canvasses views on whether there should be additional arrangements to facilitate the coordination of generation and transmission with respect to transmission investment to facilitate the development of REZs. In particular, the AEMC posits that transitional arrangements could support REZ development, ahead of the introduction of the broader COGATI reforms.

The development of transmission to support a REZ can occur through:

- Transmission investment that is considered to be 'connection assets', and which are developed by a party on a contestable basis; or
- Transmission investment that is considered to be part of the 'shared network', and which is evaluated and justified on a strategic, integrated basis as a regulated investment through the ISP and subsequent individual TNSP RIT-T assessments. As such investment is more likely to relate to uncertain forecasts of future generation investments, it can be difficult to justify through this route.

Energy Networks Australia agrees that more effective measures for achieving the coordination of generation and transmission investment (both shared network and connection assets) to support the development of REZs (or any significant, connection style asset that involves multiple generator parties) are required. Energy Networks Australia suggests that the consideration of the approach to REZs be facilitated via a more focused consultation process, rather than as an 'add-on' to the consultation on the broader access reforms. It is also important that the AEMC's consideration of this issue is coordinated with the work being done by the ESB and ARENA on models for REZ development.

The intrinsic difficulty at present with achieving the necessary level of generator commitment is a combination of:

- the fact that generators are in competition with each other and have different investment timeframes, so that any coordination between generators is difficult to achieve;
- the much shorter lead-times for generator investments compared with transmission investments;

- the much shorter duration for generation investment than those for transmission investment, which gives rise to a 'stranded asset' risk for long-lived transmission assets;
- as the AEMC has recognised, the appetite for generators to make any financial contribution to transmission capacity is limited by the absence of any access commitments able to be offered in return for such financial contribution (an issue which, in the longer-term, would be addressed through the introduction of LMP and long-term transmission hedges); and
- 'out of market' changes, such as government funding of new generation, that impacts the profitability of privately funded generators and therefore their appetite to progress their projects and hence support REZ development.

In assessing the options for arrangements to support REZs, Energy Networks Australia encourages the AEMC to focus, in the first instance, on establishing some high-level principles to guide its policy development in this area. These should include that:

- the strategic view of NEM transmission and generation development articulated in the both the existing ISP and future updated ISPs should be taken into account – by the nature of the assessment undertaken for the ISP, the 'roads to nowhere' motivation identified by the AEMC may reasonably be considered less applicable to the REZs identified through this process;
- by their intrinsic scale efficiency, the concept of REZs can be expected to result in more efficient and lower cost consumer outcomes than any decentralised process for achieving generator commitment of the kind contemplated by the 'generator access standard' element of the directions paper;
- that the arrangements, which could apply to assets with a 50 year life, can sit alongside the broader COGATI reforms, and be applied on an enduring basis as the transmission network develops; and
- TNSPs should not be exposed to risks outside of their control as part of the REZ arrangements and should receive adequate compensation for the risk borne.

Bearing these principles in mind, Energy Networks Australia urges the AEMC to consider a range of mechanisms that would assist the development of REZs. These options need not be mutually exclusive, reflecting that REZ development will not be 'one-size-fits-all', and different parties are expected to benefit from REZ development, and this may vary between specific REZs.

The options considered should include:

- the exploration of an open season type process as indicated under AEMC's option one, which may assist in being able to corral generators and thereby achieve an important level of visibility as to generator investment intentions.
  - This approach could be adopted where REZ assets are being developed on a contestable basis as 'connection assets', or could potentially be adopted as part of the planning approach in considering shared network augmentation as part of the ISP and regional planning;

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- However, the proposed annual frequency of the open season is likely to undermine generators' incentives to sign-up to an open season substantively ahead of time;

» the government-supported funding approach being developed by the Energy Security Board; and

» the use of some form of down-payment or transmission bond (including as part of an open season process), so that generators (or other parties) can back their intentions by putting up of financial commitments, some portion of which may then be refunded once those generators have connected to the developed REZ:

  - this approach could eventually be subsumed into the approach proposed by Energy Networks Australia in section 6 for long-term transmission hedges for shared transmission investment more generally, under which generators who provide a bond would be able to participate in an auction for long-term hedges.

Although Energy Networks Australia supports consideration of flexible funding arrangements, we have a number of reservations regarding the 'PIAC model' canvassed in the directions paper.[18] Energy Networks Australia understands that under this model:

» the prescribed 'efficient' size of REZ development would be determined by AEMO as part of the ISP, who would form this view based on a variety of input sources, not only the relevant TNSP's forecast of expected future generation at the REZ;

» investment by the TNSP would be required to reflect the efficient size determined by AEMO (or could exceed it if the TNSP decides to undertake additional 'speculative' investment), but could not be less than this size, even where the TNSP's own view of future expected generation at the REZ was less than AEMO's;

» as a consequence, the risk faced by the TNSP with regard to the extent and timing of future generation connection at the REZ up to the prescribed capacity would be determined by AEMO's assessment in the ISP;

» further, the additional return earned by the TNSP for bearing this risk up to the prescribed capacity would be determined by the AER, rather than by the TNSP's own view of the compensation required for bearing this risk.

As a consequence, this model appears to set up a fundamental disconnect between the party bearing the risk (the TNSP) and the parties who determine the extent of that risk (AEMO) and the compensation for bearing that risk (the AER). This can be expected to lead to a very real risk of the investment not proceeding.

We also note that the 'generators pay 50 per cent' aspect of the model (or some other ratio that may be determined) may well discourage rather than encourage

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[18] As outlined in the directions paper, and set out in the paper provided by PIAC to the Technical Working Group, *PIAC's framework for centralised supply investment and model for generation-leading transmission investments*, May 2019

generator commitment, unless it is part of a transmission hedging solution under which the relevant generators would receive some form of right for whatever contribution they make.

There are also fundamental questions about how the model would integrate with the longer-term LMP/hedging reforms and how it would apply in an increasingly interconnected, shared network with related implications for the pricing of unregulated versus regulated network assets.