2 August 2019

John Pierce
Chairman
Australian Energy Market Commission

Lodged online: www.aemc.gov.au

Dear Mr Pierce

AEMC: COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT DIRECTIONS PAPER

Origin Energy Limited (Origin) welcomes the opportunity to provide feedback to the AEMC on the Coordination of Generation and Transmission Investment (COGATI) Directions Paper.

Origin continues to hold concerns around certain aspects of the AEMC's approach under this review process, and we suggest that the AEMC:

- Be clearer in defining what problems is looking to solve, and the extent to which it is feasible or appropriate to address all transmission related challenges through the proposed model;
- Meaningfully consider alternative options including deep connection charging;
- Develop a framework to allow for a cost benefit analysis of all options under consideration;
- Revise its implementation timeline to allow for adequate review of all the pertinent issues; and
- Acknowledge that grandfathering will be crucial for existing generators if the current model is adopted.

We expand on the above issues in greater detail in the attached submission. We have also included a report from economic consultants Castalia Strategic Advisors that provide some useful insights into the current review process.

Should you have any questions or wish to discuss this submission further, please contact Steve Reid at Steve.reid@originenergy.com.au or by phone, on (02) 9503 5111.

Yours sincerely

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1. Defining the issues

It is important that the AEMC clearly (and accurately) define the issues it is looking to address as this will have a direct bearing on the appropriateness of the overall approach. Origin continues to hold concerns around some key aspects of the AEMC's problem definition. We do not agree that access reform is a panacea for all transmission related challenges in the market or that the proposed model is the only (or best) means of addressing these matters. We discuss these issues further below.

Ensuring the robustness of the NEM's locational signals should be a priority

Traditionally the NEM's locational signals have generally worked well in incentivising efficient decision making. There are now indicators, however, that this is being tested by the changing pattern and nature of new generation entering the market. The variable and somewhat unpredictable nature of marginal loss factors is sometimes seen as being symptomatic of this.

New entrant generators typically balance multiple factors when deciding on where to locate. These include loss factors, network congestion, and fuel availably. It is possible that the rapid influx of new generation, and the nature of these plant has upended this balance with fuel availability (i.e. access to wind, sun) now seemingly have a greater bearing on location decisions. As part of this review the AEMC should seek to understand the underlying reasons for any poor locational decisions. One critical consideration is the extent to which a lack of transparency around new connections has contributed to any poor or irrational locational decisions; and the extent to which this can be addressed by the recent proposed changes in this area[1]. If the AEMC concludes that the NEM's locational signals do require strengthening, a causer pays framework that incentivises better decision making on the part of prospective new entrants should also be considered. Under such an approach, generators that choose to locate in areas that are not aligned with the efficient development of the network, would bear some cost of doing so. This would be consistent with the 'do no harm' provisions recently introduced for system strength[2]. We discuss this approach further in Section 4.

The proposed model does not address main obstacles to Renewable Energy Zones (REZs)

The current access regime has not been the limiting factor in the development of REZs. Instead, the main barrier has been the challenges in coordinating the activities of multiple prospective generators, and the likely need to oversize the connection asset. The AEMC's model focuses on access to the shared network and does not address these issues. We agree that once the complexities relating to the building/funding of a remote connection asset are resolved, access to the shared network will also be important, particularly given the significant volume of energy that is likely to enter the market through a REZ. It is our understanding that the ranking of REZs in the Integrated System Plan (ISP) also includes an assessment of any augmentations to the shared network that would be required to facilitate the connection of the asset. Given this, where a REZ is earmarked for development in the ISP, this should represent the least cost approach of bringing the energy market, therefore minimising the costs borne by consumers. Therefore, the outstanding issue in relation to REZs is actual construction of the connection asset, which is not dealt with by the AEMC's proposal.

Mis-pricing is not a material issue

As previously highlighted throughout this consultation, the incidence of disorderly bidding or mis-pricing is not material and therefore cannot reasonably be used as a means of justifying the AEMC's suggested

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[1] The AEMC published a draft determination on 1 August aimed at increasing the transparency of new projects entering the market.

[2] As part of 2017 rule change, the AEMC place an obligation on new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system

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approach. While the AEMC states that disorderly bidding could become more problematic in the future, there is no evidence to support this.

2. The proposal model has some significant practical limitations

Unlikely to facilitate greater coordination of generation and transmission investment

The efficient coordination of generation and transmission investment is crucial in ensuring the long term viability of the NEM. The Directions Paper states that this is now challenging given the current market transition, and there is a risk that consumers will bear unnecessary costs if transmission lines become roads to nowhere. While Origin agrees with these comments, we do not agree that the proposed model will facilitate more efficient coordination, or help to effectively manage the inherent risks associated with transmission planning and investment, given that:

- The melding of a regulated and market driven approach is unworkable**.** The AEMC's model implies that transmission planning and investment would be driven by a centrally planned regulated process in line with AEMO's ISP and regional transmission companies; as well as individual generators acquiring financial transmission rights (FTRs). However, it is unclear how the incremental approach of FTR purchases will effectively interact with the ISP and the Regulatory Investment Test – Transmission (RIT-T) particularly given the lumpy nature of transmission investment. We do not consider this to be workable or particularly efficient.

- The physical nature of the shared network is such that the costs of augmentations are most appropriately socialised. Given Kirchoff's Law, electricity flows along multiple paths or loop flows which means that is typically not possible to attribute the impacts of a particular transmission asset/augmentation.

  These characteristics of transmission infrastructure seriously limit the extent to which 'market forces' can be introduced in the provision of transmission services, and in particular investment. Decentralised investment would result in network investment which is insufficient or non-optimal from a wider public policy perspective. In practice, this means that the costs of the operations of the network and transmission investment will continue to have to be recouped via regulated transmission charges of some kind[3].

- Ultimately it is the robustness of the RIT-T and ISP process that will minimise the cost and risks borne by consumers. Any concerns around inefficient transmission investment are most appropriately addressed by ensuring that both the ISP and RIT-T manage the inherent risk of asset stranding and over-investment.

Increase in basis risk could have negative implications for contracting

There are trade-offs when considering any access regime. Origin remains concerned that the choice of moving to locational marginal pricing presents challenges for the NEM's energy only gross pool design, which is underpinned by financial contracting. The introduction of locational pricing will create basis risk where there is divergence between the local and regional reference prices. The AEMC have indicated that generators would also be able to procure FTRs to manage this risk. There are, however, ongoing concerns regarding the adequacy of the revenue stream coming from FTRs and the complexity of the arrangements.

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[3] London Economics 1999: *Review of Australian Transmission Pricing, pg. viii*

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3. Alternative approaches should be explored

It is crucial that the AEMC explore alternatives to ensure that a fuller suite of options can be considered. Ultimately this could also serve to reinforce the merits of the AEMC's approach if it is proven to provide a greater net benefit compared to other options.

The AEMC should also examine the extent to which targeted solutions can help to resolve some issues, compared to the reliance on an all-encompassing model that is seemingly being designed to tackle every transmission related problem in the market. As mentioned earlier, the new transparency measures could help to improve locational signals. Additionally, the challenges around REZ development require consideration of options beyond what is covered in the access reform package.

Origin also suggests that the AEMC explore a causer pays framework whereby prospective generators bear some costs if their locational decisions are not aligned with the efficient development of the transmission system, e.g. through some type of deep connection charging framework. Consistent with the 'do no harm' provisions for system strength, projects whose location result in an increased level of congestion beyond some pre-determined level could be subject to the charge. Generators that locate along transmission paths set out in the ISP could be deemed to be locating in areas consistent with the efficient development of the network and therefore not subject to additional charging in relation to the shared network. This approach would by no means be perfect and the detail would need to be worked through. It would also place great emphasis on ensuring that there is a robust and transparent process around the development of the ISP.

Another option that should be considered is a full nodal pricing approach. While Origin does not support a move to nodal pricing, it is important to understand the differences between the AEMC's partial locational pricing approach and full nodal pricing.

4. Existing generators should be grandfathered if the proposed model is implemented

As highlighted earlier in this submission, the AEMC must be clear on the reasons for pursuing the proposed model. If the conclusion is that there is a need to improve locational signals in the market, existing generators should be excluded from the new arrangements given they are unable to change their location. Measures aimed at improving locational signals should be targeted at generators looking to enter the market.

It is also important to note existing generators decided to enter the market under vastly different transmission arrangements to what is now being contemplated. While it is unrealistic, to expect the policy framework to remain static, it would not be good regulatory practice to impose such a significant change on existing plant, particularly at time when reliability and orderly generator exit are crucial given the current market transition.

5. Potential next steps

Origin suggests that the AEMC considers the following next steps as part of the review process:

1. Broaden its approach to consider other options.

2. Develop an assessment framework that can serve as the basis of a cost benefit analysis for options under consideration. While we acknowledge that any cost benefit analysis will be challenging, it is unreasonable for the AEMC to embark on such a significant reform without such

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an assessment. Issues that should be covered include: implications for the contracts market; alignment of the proposed option with the current or possible future wholesale market design; cost of implementation; transitional arrangements; implications for dispatch efficiency; and the likely impact on existing and prospective generators.

3. Evaluate the appropriateness of the proposed implementation timeline. We maintain the view that the current timeline is overly ambitious, unrealistic, and runs the risk of rushing what is an important reform. Even if there was consensus around the AEMC's model (currently there is not) more time would be required to work through the detail.

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Supplementary Submission on AEMC's Proposed Transmission Access Reforms

Report to Origin Energy

September 2019

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Executive Summary

The AEMC has identified the need for better coordination of transmission and generation investments as one of the key emerging challenges as Australia transitions towards a renewables-based electricity system. The existing transmission grid has been developed over the years to serve a fairly stable geographic pattern of load and generation. Until the recent renewables boom, incremental transmission upgrades within each NEM zone had been relatively modest and low risk.

By contrast, on-going investment in renewables is placing considerable pressure on the electricity transmission grid as it transforms not only the technology of how electricity is generated and consumed, but the geographic location of both load and generation. The unprecedented amount of new generation investment planned over the next ten years will lead to a corresponding transformation of the transmission network.

Such transformation will pose significant costs and risk. AEMC has highlighted the risk of "lines to nowhere"—the possibility of misalignment between transmission investment and future generation plans.

In this context, AEMC is considering a number of reforms, including the introduction of locational marginal pricing (LMP), transmission hedges, and the use of transmission hedging revenue to inform and finance transmission system expansion.

While Australia is not alone among the world's electricity markets in seeking to address the challenge of improved coordination between transmission and generation investment, the AEMC appears to be alone among its global peers in considering the introduction of LMP and transmission hedges as the key solution to the challenge.

Since the AEMC has drawn on the international literature and some aspects of international experience as the justification for its approach, this paper considers whether the AEMC is correctly interpreting lessons from other markets.

We conclude the AEMC has misinterpreted the lessons from other jurisdictions. While LMP may provide some operational benefits, a careful reading of international experience indicates LMP and transmission hedges will not help in solving the coordination problem correctly identified by AEMC. Given the complexity of introducing LMP, the diversion of effort into the reform program proposed by AEMC would likely mean that the fundamental problem of coordination will remain unaddressed.

Several alternative reforms, not yet considered by the AEMC, provide more straight-forward and workable solutions. This paper suggests directions for further inquiry by the AEMC, rather than rapidly implementing a solution which will fail to meet its objectives.

1 Introduction

The AEMC is considering a number of reforms, including the introduction of locational marginal pricing (LMP), transmission hedges, and the use of transmission hedging revenue to inform and finance transmission system expansion. These reforms are proposed to address concerns about efficient transmission investment in the context of rapid build out of new renewable generation capacity.

The purpose of this paper is to provide international perspectives on:

- The need to better coordinate generation and transmission investment (**Section 2**)
- The AEMC's proposed way of addressing this challenge (**Section 3**), and
- Alternative approaches to meet the challenge (**Section 4**).

The key finding is the AEMC has correctly identified the need to better coordinate generation and transmission investment in the NEM. Regulatory and market reform is indeed necessary to ensure the NEM's regulatory framework evolves in line with technological changes in the market.

However, there are significant limitations to the reform proposed by the AEMC. Accordingly, we propose alternative approaches the AEMC should investigate.

This report was prepared at the request of Origin Energy by Alex Sundakov, Andrew Swanson, Carl Hansen and Jamie Carstairs.

2 Need to Coordinate Generation and Transmission Investment

In its June 2019 Directions Paper, the AEMC outlined two high-level objectives[1]:

- Better coordination of generation and transmission investment, and
- Evolving the NEM's regulatory framework with technological advancements.

These objectives derive from the rapid energy transformation occurring in Australia. Transmission network service providers (TNSPs) have received connection enquiries for about 50 GW of new generation over the next decade. This is about the same as the NEM's total existing generation capacity. With most of the proposed investment in variable renewable generation, the location of new generation units will differ significantly from existing plants which they will be eventually replacing. This means that energy transformation will also involve a fundamental reshaping of the national transmission grid.

While the reshaping of the transmission grid may be inevitable, significant efficiencies could be achieved by minimising the degree of change in the transmission infrastructure and avoiding unnecessary system upgrades or system stranding.

The AEMC has identified four key components to the problem of investment coordination in the NEM. For a summary, see Table 2.1.

Table 2.1: Summary of Problems Identified by the AEMC

Problem	Features
Locational	Prospective investors are planning to connect new generation in locations where the transmission network has limited or no capacity to evacuate additional generation
Financial uncertainty	Generation investors are uncertain about the future profitability of their assets, with the risk of future investors crowding-out access to the transmission system
Stranded assets	AEMC is concerned about so-called 'lines to nowhere' if TNSPs do not accurately foresee the location of future generation investment
System security	Generators and TNSPs are finding it difficult to comply efficiently with 'do no harm' system security obligations for new connections

2.1 Problem Not Unique to Australia

Australia is not alone among the world's electricity markets in seeking to better coordinate investment in new generation and transmission. Rapidly falling costs for renewable generation, along with policies targeting emissions reduction in many countries, are combining to undermine the commercial viability of investing conventional generation technologies. This, in turn, requires changing the way transmission systems are planned and financed, including the access regime for generators.

There has been extensive debate in the academic literature, and among regulators around the world, about the best way to achieve optimal coordination between generation and transmission investment.

[1] AEMC (2019) 'Coordination of Generation and Transmission Investment – Directions Paper'

Below, we consider theoretical perspectives on the need to coordinate generation and transmission investment in energy-only markets such as the NEM. We then turn to practical examples of how the problem is being addressed internationally.

2.2 Theoretical Perspectives on the Problem

Australia's NEM is one of the few energy-only gross pool markets in the world. The United States is dominated by capacity markets, such as the pool operated by PJM in the country's northeast and Midwest.

Europe is dominated by net pools, in some cases energy-only and in others with a capacity market. These markets set prices on a national or zonal level. The United Kingdom provides an example. It used to have an energy-only gross pool in England and Wales. This was similar to the NEM although without the zonal structure. After several changes it now has a net pool for energy and a capacity mechanism. For both energy and capacity there is a single price across the market.

Table 2.2: International Comparison of Electricity Markets

Market	Energy-Only	Gross Pool	Nodal Pricing
NEM	✓	✓	✘
New Zealand	✓	✓	✓
United Kingdom	✓	✘	✘
PJM	✘	✘	✓

Only New Zealand provides an example of a comparable market with an energy-only gross pool. This raises two questions. The first is whether a move to introduce nodal pricing in the NEM – and so become more similar to the New Zealand market design – can be expected to help with the challenges in co-optimizing generation and transmission. The second is whether a move in the directions suggested by other markets would be preferable.

The introduction of nodal pricing in the NEM may create more transparent price signals. It is arguable how material this will be. Generators are already subject to volume risk and have strong incentives to avoid congested areas.

However even if we accept the proposal may increase the transparency of price signals on congestion, would that improve the co-optimization of investment? It could only do so by improving at-risk investments or by improving planning.

Improving at-risk investments

In gross pool energy-only markets, there has been a recurring theoretical hope that price arbitrage between locations can direct and help pay for necessary transmission investment. The hope is investment in response to price arbitrage opportunities is more efficient than planned investment, because it responds to market incentives rather than to central planners' beliefs.

There has been material merchant investment in some markets and in particular in the US. No-one considers that this could or should be the sole basis for transmission investment:

- Merchant transmission has generally been for point-to-point HVDC links between different markets. Given the club nature of intra-zonal transmission it could not capture the benefits of investments within a meshed AC network
- There are fundamental problems for securing the benefits of additional transmission which reduces price dispersion between regions. As we discuss later, FTRs provide some short-term contractual protection. However, there is no practical way merchant transmission investors can capture the benefits of reducing price dispersion over the medium term. The MNSP model requires withholding of capacity to maintain price dispersion in order to generate price arbitrage. This is exactly the opposite of what well-planned transmission investment achieves
- There is academic consensus the revenues from sale of transmission hedges are less than the efficient costs of expanding the network. This model does not solve the financing problem.

We also note that the merchant model has not worked well in the NEM. The AEMC proposals seek to replicate at the intra-regional level the model that already exists at the inter-regional level. At the inter-regional level, the co-existence of regulated transmission network service providers (TNSPs) and market network service providers (MNSPS) represented a compromise trial of the merchant model. Merchant investors were protected by the regulatory back-stop—the opportunity to convert to a regulated status subject to the application of the regulatory investment test.

Over the last two decades, there have only been three MNSPs, two of which sought regulatory conversion within a few years of coming online. The third, Basslink, is known to be experiencing technical and commercial challenges. For more on the MNSP experience in the NEM, see Box 3.1.

Improved planning

Given the monopoly nature of core transmission grid investment, all markets, regardless of design (energy-only, capacity, gross pool, or net), rely on some form of regulation and central planning to coordinate generation and transmission planning. Across all market designs, investment in transmission is primarily driven by system planning considerations rather than relying on merchant-driven investment undertaken in response to market price signals.

There are a number of theoretical reasons for concluding such reliance on central planning to guide transmission investment is inevitable:

- The “club good” aspect of a meshed AC transmission grid makes it difficult to identify the beneficiaries of investment and secure adequate investment from price signals.
- Transmission networks have system reliability obligations, with considerably less tolerance for inadequate investment compared with individual generators.

This raises the question whether the AEMC proposals could improve planning. As discussed above it may provide more transparency on congestion costs by node. These costs are already known to transmission planners. All markets, including those with a uniform national price, take account of congestion costs in transmission planning. Generators are already exposed to volume risk from congestion. The impact of the proposals on both generation and transmission planning may be low.

The US pools and several European markets are introducing capacity mechanisms. While the design varies these typically allow for the System Operator (SO) to identify and put up for auction the firm capacity required three to four years ahead. That sets a price for capacity either across the market as a whole or on a zonal basis.

Even if this change were made to the NEM it would not materially address the co-optimization of generation and transmission. The rationale for these capacity mechanisms is to ensure sufficient firm capacity a few years ahead rather than to assist with transmission planning. Non-firm renewables do not participate so the full information needed for co-optimization is not covered.

Our conclusion is that the AEMC proposals will not materially assist the integration of generation and transmission planning and that the introduction of a capacity mechanism would also not assist. The main requirement is to alter the planning framework. Again, international experience shows how this can be done. The SO can play a greater role; the TNSPs can continue to assist in the early stages of project identification and development; and competitive tenders rather than regulation can be used to minimize costs and incentivize availability.

The AEMC's proposals are based on more "market-oriented" logic: the current compromise between central planning and market-based decision-making in the electricity sector is not working and requires more reliance on market mechanisms. This contradicts the rational for AEMO Integrated System Plan (ISP): the current compromise between central planning and market-based decision-making in the electricity sector is not working and requires more effective central planning mechanisms.

One could debate the overall role of central planning in market coordination within NEM. However, it is clear the AEMC's proposed introduction of nodal pricing could be at odds with other reforms being considered for NEM. To illustrate the dangers of uncoordinated NEM reform, we turn to relevant international experience.

2.3 International Perspectives on the Problem

Given the need to coordinate generation and transmission investment is not unique to Australia, the AEMC should consider lessons from international markets.

Below, we consider two such examples:

- New Zealand, and
- The United Kingdom.

2.3.1 New Zealand

Like Australia's NEM, New Zealand operates an energy-only market. However, as recognised in the Directions Paper and during the AEMC's recent stakeholder workshops, the New Zealand market also has full nodal pricing and Financial Transmission Rights. It has been suggested this provides international precedent for the reforms the AEMC is proposing for the NEM. However, we find the New Zealand market actually shows the limitation of nodal pricing and FTRs to address investment coordination.

There are two key reasons for this:

- Persistence of poor coordination in New Zealand market despite LMP, and
- Introduction of FTRs hasn't improved coordination.

Persistence of poor coordination despite LMP and FTRs

In broad terms, the existing New Zealand regulatory framework is similar to the AEMC's proposed approach. These similarities mean the New Zealand experience offers Australian policy-makers a useful real-world demonstration of whether locational marginal pricing and transmission hedging materially assist with coordinating generation and transmission investment.

However, the New Zealand market provides an example of why the AEMC's approach probably will *not* support the coordination of generation and transmission investment. In fact, there are examples where locational pricing and transmission hedges may have facilitated poor investment coordination. This can occur because locational marginal prices are greatly affected by generation and transmission investments, and generators in New Zealand face zero long-term transmission prices for accessing interconnection assets.

The New Zealand Electricity Authority has long recognised that inefficient generation and grid investment occurs with locational marginal pricing, due to the economies of scale and lumpiness of transmission investments. For example, in appendix D of a consultation paper on transmission pricing entitled 2019 Issues paper, the Authority states:[2]

> *"However, because there are economies of scale in transmission services, nodal prices are generally insufficient to recover the cost of the investment. This is compounded by the lumpiness of transmission investment. (para D.48)*

This means that if we were to rely solely on nodal prices to price use of and access to the grid, users would be charged less than the full cost of supplying electricity:

> *"Charging users less than the full cost of production may lead to inefficient grid investment, as it draws in demand from those customers who would not be willing to pay for it if they were to face prices based on total cost of the investment. Likewise, grid users would also have an incentive to make investment decisions that took into account the nodal prices* ***but not the impact of their decisions on the need for grid investment****." (para D.51, emphasis added)*

Significant grid investment decisions in New Zealand require the approval of the Commerce Commission, which makes its decisions using cost-benefit analysis. The Electricity Authority explains why this approach still leads to inefficient grid investment (even under LMP):

> *"The Commerce Commission is charged with ensuring that grid investment is efficient. The Commerce Commission's grid investment approval processes provide a robust method to test the costs and benefits of investment proposals. It is sometimes argued that this negates the need for a transmission charge on beneficiaries of an investment. We disagree. The Commerce Commission's process and analysis provides for transmission investment that is efficient given the decisions of grid users. In the case of the gas-fired power station above, it must provide for grid investment given the investor's decision to locate the power station next to the gas field. As a result, even if the Commerce Commission's decision is efficient given grid use, it is still the case that outcomes could be enhanced overall by our proposal." (para D.62)*

Nodal prices reflect operational conditions and are determined by the state of the electricity system in each half-hour period. Although nodal prices can signal where investment is needed, they are also greatly affected by such investments because they're lumpy. It is not just that nodal pricing affects investment, but investment also affects nodal prices. This circularity means it is easy to misinterpret evidence about the coordination of generation and transmission investment.

[2] Available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c18138

Similar to nodal pricing, cost-benefit assessments of transmission investment proposals take existing generation, even very recent generation investments, as a given. This creates a time-consistency problem for deciding some transmission investments: generators can locate new plant upstream of heavily congested transmission circuits knowing that, although they will receive relatively low nodal prices until a transmission investment is made, their generation investment "forces the hand" of the transmission provider and the Commerce Commission when it results in a positive net economic benefit from transmission investment.

To address these issues the Electricity Authority is proposing to introduce a benefits-based charge for access to interconnection assets so that generators take into account the transmission costs of their location decisions and to encourage them to support Transpower grid investment proposals only when the combined transmission and generation costs are lower than for other options.

The Authority recently estimated this part of its transmission pricing proposal will deliver economic benefits of NZ$145 million (AU$137 million) over the modelling period, from more efficient investment in transmission and generation (and more efficient consumer decisions about connection, electrification and location)[3]. These efficiencies arise despite New Zealand having a very well-functioning locational marginal pricing system and transmission hedges available at key nodes on the interconnection system.

As discussed in the introduction, it is easy to misconstrue evidence of better coordination of generation and transmission investment, and this appears to have occurred in James Flexman's presentation on 8 July 2019 to the CoGaTI public forum. Mr Flexman is the wholesale markets manager for Mercury, a New Zealand generator-retailer, and is referring to New Zealand experience with locational marginal pricing. He stated:

> *"Nodal pricing [in New Zealand] provides important locational signals for generation investment [and] signals to the Grid Owner as to where grid capacity is close to maximum and where grid investment is needed" (slide 25)*

Although both statements could be true, it does not support AEMC's coordination proposition because of the time-consistency problem: Mr Flexman's statement ignores the fact generation investment drives nodal prices, which then signal where transmission investment is needed. This leads to inefficient coordination when generators undertake investments that "force" inefficient transmission investment (because generators do not face appropriate long-term transmission prices).

Introduction of FTRs hasn't improved coordination

Nor have financial transmission rights improved the coordination of generation and transmission investments in New Zealand. This is because financial transmission rights are auctioned in New Zealand. Buyers of financial transmission rights pay up to the present discounted value of the pay-outs they expect to receive from holding the financial transmission rights. The auctions effectively swap volatile half-hourly surpluses, for less volatile monthly or quarterly surpluses. But they do not alter the average impact of nodal prices.

Mr Flexman made the same point in his public forum presentation:

3 See 2019 Issues paper at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c18138

> *"Financial transmission rights … do not financially contribute towards a generator's ROI …". (slide 23)*

The original thinking behind financial transmission rights was to give them to generators that paid for interconnection investments, rather than auction them. Professor William Hogan, who authored the concept of transmission rights, recognised it is not technically feasible for generators to receive physical capacity rights over interconnection circuits they pay for.[4] Generators therefore will therefore want to pay for such transmission investment (regardless of the market-wide efficiency of such investment).

Due to 'loop flows' on interconnection circuits, generators elsewhere in the electricity system could free-ride on the new capacity others had paid for, by altering the way they operated or by undertaking new generation investments. Either way, the generators paying for interconnection circuits could be crowded-out from dispatch and receive suppressed nodal prices.

Professor Hogan realised this free-rider problem could be resolved by the transmission provider creating financial transmission rights equal to additional interconnection capacity, and giving them to the generators paying for the capacity expansion. This would facilitate generators paying (long-term prices) for interconnection investments, which in turn would drive better coordination of generation and transmission investments because the transmission provider would secure sufficient long-term contracts with generators (and other long-term grid users) to pay for transmission expansion before undertaking its investments[5].

Auctioning financial transmission rights largely removes their coordination role; they largely become a risk-management instrument rather than an instrument to address the free-rider problem.

Although Transpower New Zealand proposed in 2000 the direct allocation of financial transmission rights to generators willing to pay for new interconnection capacity, financial transmission rights were not introduced until 2013 (under the direction of the Electricity Authority)[6]. The auction approach was adopted.

Mr Flexman stated in his presentation to the CoGaTI public forum that transmission hedges facilitate the retirement of generation plant. He states that:

> *"FTRs (combined with Futures) allow retirement of generation plant… Mercury retired uneconomic thermal peaking plant in Auckland and now buys Futures to cover energy (volume) risk and FTRs to cover locational price risk" (slide 24, CoGaTI Public Forum, 8 July 2019).*

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[4] See William Hogan (1992) *Contract networks for electric power transmission*, Journal of Regulatory Economics, vol 4, pp.211-242; Scott Harvey, William Hogan, and Susan Pope (1996) "Transmission capacity reservations and transmission congestion contracts," Center for Business and Government, Harvard University, (revised 8 March, 1997); and William Hogan (1999) "Market-based transmission investments and competitive electricity markets," Center for Business and Government, Harvard University.

[5] In other words, transmission investments would only proceed if generators thought the costs of bundle 1 (new upstream generation + new transmission capacity) were lower than the costs of bundle 2 (new downstream generation where there is no need for additional transmission capacity).

[6] Under Transpower's proposal, investors in new interconnection capacity would be offered (but not obliged to accept) a succession of one-month financial transmission rights for the life of the investment, between nodes of their choosing, and for the incremental capacity created by the investment. See a report for the FTR Working Group by Lew Evans and Richard Meade (2001) "Economic analysis of financial transmission rights (FTRs) with specific reference to the Transpower proposal for New Zealand," New Zealand Institute for the Study of Competition and Regulation Inc., September 2001.

However, this is actually an example of nodal pricing and transmission investment driving out downstream generation, bringing forward the need for expensive transmission investment. This is the opposite of better coordination. It occurred even though New Zealand has locational marginal pricing. The details are as follows:

- Mercury decided to retire their Southdown generation plant in Auckland after a major grid upgrade was completed that allowed far greater electricity to be transmitted northwards into Auckland.
- This greatly reduced the nodal prices and operating hours for the Southdown plant, rendering it uneconomic. Contact Energy's plant at Otahuhu (also near Auckland) and two of Genesis Energy's plants at Huntly (in the Waikato) suffered the same fate.
- Since the closure of these plants, the national grid provider—Transpower New Zealand Limited—has been working on options for achieving greater voltage stability to further strengthen northward transmission into Auckland once the remaining two Genesis plants at Huntly are retired[7].

Importantly, Mr Flexman did not present his slide as an example of better coordination of generation and transmission investment. The slide is headed "Nodal pricing + FTR's – Operational implications" and it states:

> *"Physical generation assets don't fully cover retail market risks related to nodal pricing … FTRs reduce locational price risk for retailers holding 'traditional' hedge products." [Emphasis added] (slide 24)*

Mr Flexman's example does not appear to be provided as evidence of better investment coordination. Rather, he is providing an example of how locational marginal pricing can actually work against coordination. Decisions by Mercury, Contact, and Genesis to retire plants in Auckland and Waikato were about using the futures market and transmission hedges, rather than physical generation, to better manage retail risk. The decisions had nothing to do with coordinating generation and transmission investment.

For more on the New Zealand market, see 4.6Appendix A.

2.3.2 United Kingdom

Further insight on the challenge facing the NEM can be gained by considering recent reforms in the UK market, which faces a similar technological transition to renewable generation. Like Australia's NEM, the UK operates an energy-only gross pool. However, unlike the NEM (or indeed the New Zealand market), the UK market only has a single price region.

Nevertheless, the UK market is sufficiently similar to the NEM to justify the comparison.

We consider two policy reviews undertaken in the UK in recent years, seeking to address the need for better investment coordination:

- Transmission access reform, and
- Integrated transmission planning and regulation, and

[7] For example, see discussion of the Waikato and Upper North Island (WUNI) project on pp. 36-38 of Transpower's 2017 Transmission Planning Report, available at https://www.transpower.co.nz/sites/default/files/publications/resources/Transmission%20Planning%20Report%20Final.pdf

Neither of these reviews recommend locational pricing and FTRs to achieve better coordination. Nor has the UK market (or, to the best of our knowledge, any market) made transmission expansion fully dependent on revenue from transmission hedges.

Review one: Transmission access reform

Over the last two decades, emissions reduction targets in the UK have encouraged the rapid connection of new generation, and a higher level of installed generation capacity in relation to the transmission network.

In 2007, UK generators were facing delays of 10 years or more to connect. This is analogous to the AEMC's concern about TNSPs being inundated by requests totalling about 50 GW of new generation capacity over the next decade, and the potential for delays assessing these connection requests.

In response to delayed connection requests, response, a major review of transmission access arrangements was announced in a Government White Paper in 2007. It was undertaken jointly by the Government Department then responsible for energy (BERR) and by Ofgem, and completed in 2008.

The transmission access review was driven by the need to meet abatement targets. Modelling suggested that around 35 GW of new low carbon generation would be needed. This required:

- More transmission capacity to enable this generation to connect
- Better use of transmission capacity: The additional 35 GW forecast was against similar demand. Large volumes of intermittent generation were to be brought on together with firmer back-up. This implied more MW of installed capacity per km of transmission and more intensive use of the transmission system, and
- Early works: Connection is provided against commitments by generators. Delaying work until generators had obtained planning approvals and those commitments were received would substantially delay progress on abatement targets.

These requirements were not being met. Transmission owners were unwilling to invest in advance of commitment. System operation was undertaken within the largest transmission owner, National Grid. Rapid connection increased constraint costs. These costs are partially borne by the SO creating a disincentive to connect. The result was delays of ten years or more in granting connection to the transmission system.

The review considered three models for access reform:

- Model A was to 'connect and manage'. Generators would be offered connection in line with their development schedules and the transmission owners and SO would manage the consequences with supporting measures by the regulator.
- Model B was to establish and trade a range of access products. The existing access product was firm access at all periods and for an indefinite period provided annual payments were made. Less firm and shorter access products were considered.
- Model C was to establish local marginal pricing for each half hour at all transmission nodes. This would be accompanied by a new hedging product, known as FTEC. This was a financial hedge that gave similar firm access to the existing TEC. Model C resembled the AEMC's proposed establishment of

locational marginal pricing and hedges although without the further explicit link to transmission planning and financing in those proposals.

The review recommended Model A. This model was judged more effective at bringing on new generation. The review recognised constraint costs were not explicitly priced and were passed on to consumers. However, it concluded constraint costs would still create a strong signal for reinforcement even in the absence of locational pricing.

Model C would require a new instrument to be developed; created some uncertainty for investors; and ran a risk that some generators did not participate in trading and so the full benefits were not realized.

This review was accompanied by a requirement for the System Operator to lead the three transmission owners in planning the 2020 requirements for the transmission system. The review also established steps for transmission owners to undertake preparatory works on projects in advance of final decisions. This was combined with a recommendation that some projects should be opened up to competitive tender, bringing an end to the onshore geographical monopolies.

The UK's 2007-08 transmission access review considered and rejected the combination of nodal pricing and hedging now being considered by the AEMC. Instead, it selected a simpler option that enabled faster connection, encouraged preparatory work on major transmission projects and modified regulatory arrangements for the transmission companies and the system operator. Rather than consider locational pricing, the policy focused on quickly connecting new generation to the transmission system as needed.

Review two: Integrated transmission planning and regulation

The Integrated Transmission Planning Review (ITPR) was subsequently undertaken by Ofgem between 2013 and 2016. The ITPR was a smaller exercise than the 2007-08 transmission access review, but still influential in the development of transmission access regulations.

The focus of the previous transmission access review had been onshore transmission. This left three different regimes:

- Regulated geographic monopolies for onshore competition
- Competitive tenders for offshore transmission, and
- Developer-led interconnections to other markets within a cap and floor.

The main changes resulting from the ITPR were to the regulatory regime for onshore transmission. When developing offshore transmission, the UK previously adopted a competitive approach. Since 2009, the estimated savings from taking this approach are estimated at £600M to £1.2 billion. The review concluded this approach should be extended to onshore transmission. Consequently, the ITPR recommended the adoption of a competitive approach to onshore transmission investment too.

The System Operator was given an enhanced role to lead identification of system needs and of options for network investment. The System Operator can also lead early development of transmission options. This is not meant to change investment decisions, which are still made by regional monopolies.

For more on the UK market, see 4.6Appendix B.

3 Limitations of AEMC's Proposed Approach

Under the AEMC's proposed approach, the need to better coordinate generation and transmission investment will remain unresolved.

In this section, we assess the AEMC's proposed approach by considering:

- The claimed benefits from the reform
- Mistaken conceptual assumptions underpinning the model, and
- The lack of international precedent.

3.1 Assessment of the Claimed Benefits

The AEMC makes a number of claims about the benefits from introducing LMP and transmission hedges in the NEM. At a high-level, the claimed benefits include:

- More efficient generation investment decisions
- Reduced risk for generators with possible benefits to the WACC
- More efficient generator dispatch, and
- Improved integration between generation and transmission, and
- Benefits to consumers because generators will pay for transmission costs through their purchase of transmission hedges

Below, we assess these claimed benefits in light of the need to better coordinate generation and transmission investment.

More efficient generation investment

Generators currently face volume risk if they are constrained off but they do not face price risk. This volume risk is material: all investors will model what risk they may be exposed to, including risk from later generation investments that reduce their access to the RRN.

The paper is correct that these risks are not very transparent, and that nodal pricing could introduce more transparency to the market. However, the AEMC have not quantified the potential benefits of such transparency—it is not possible to assess the AEMC's view of the potential scale of such gains.

The short-term nature of the proposed transmission hedge weakens the AEMC's case. The key issue for investors in assessing either volume risk if they are constrained off, or price risk with nodal prices, is the impact of new generator investment on congestion at their node. Short-term transmission hedges and nodal pricing will provide little additional transparency on such risks, since generators who have not yet entered the market do not participate in it. In other words, nodal pricing will increase transparency on the already well understood bidding behaviour of the existing generators. But it will do little to improve medium-term information.

With hedges, generators will not face short-term volume risk, but they will face uncertainty beyond the term of the hedge.

Reduced risk for generators

The introduction of hedges will reduce risk for generators. Again though, the impact will be reduced by the non-firm nature of the hedge.

There are alternative approaches that could deliver this benefit. For example, all generators could be provided with firm transmission access. The UK provides an example. All generators have a defined level of transmission entry capacity (TEC). They have firm transmission access up to the limit of their TEC and are protected against congestion on the transmission network. This would need to be underpinned and would ultimately be paid by consumers. Creating zones with a low level of intra-regional congestion would ensure the costs were low.

Moreover, hedges only reduce risk where there is high price variability and unpredictable dispatch outcomes. Otherwise, the financial hedge will simply crystalise risk by putting a price signal on it. This is because generators will need to buy the hedge—the price will simply reflect the expected value of locational price deviation from the regional spot price.

More efficient generator dispatch

When there are binding transmission constraints within a region, generators have an incentive to bid low (down to –$1,000/MWh) in order to get dispatched and get access to the regional price

The introduction of transmission hedges should remove this incentive. It seems reasonable to consider there will be some dispatch benefits. However, the materiality of the benefit has not been assessed. Nor have other options, such as smaller zones, with firm access, been considered.

If there is constraint on the export of energy, it is reasonable to assume generators willing bid the lowest price would be the most efficient plants to dispatch. The idea holds true whether generators are bidding into a regional pool, or a local nodal pool.

Further, generators with the lowest SRMC would generally be willing to pay the most for a hedge. So, in principle, there may be no difference to dispatch outcomes. In theory, a generator with higher SRMC could outbid the lower SRMC generator for a hedge, and dispatch as a result of its hedged position. In this case, the lowest cost generator may not bid low to dispatch. However, this seems to be an outlier example rather than the most likely outcome of the AEMC's proposed reform.

Improved integration between generator and network investment decisions

We find little evidence in the recent Directions Paper to support this claimed benefit of the proposed reform.

TNSPs are already aware of the costs of congestion in their network. This scheme has a similar impact to the proposed introduction of a generator access standard and the proposed (limited) exposure of the TNSPs to the costs of the transmission hedges they have sold.

It also remains unclear precisely how the revenue raised from transmission hedges purchased by generators will interact with the existing regulatory revenue that TNSPs recover from consumers. The Commission suggests one of the benefits of relying on hedging revenue to underpin new transmission investment is that generators, rather than consumers, would pay. But as far as TNSPs are concerned, who pays for part of its revenue is a secondary matter.

The primary matter is how much revenue the TNSP receives. If it continues to be regulated as a natural monopoly (and the AEMC does not suggest anything to the contrary), the AER will set their Maximum Allowable Revenue on the basis of their efficient costs. Revenue from locational hedges will not increase MAR, it will be a contribution to MAR, resulting in reduction of other charges and revenues.

As far as the TNSPs is concerned, all it will see is a substitution of more certain revenue from the traditional transmission charges by more volatile hedge revenue. It is likely that TNSPs will be entitled to true-ups rendering such substitution redundant.

In other words, from TNSPs perspective, both before and after the appearance of locational hedges they will be entitled to regulated MAR for providing the level of transmission services approved by the AER.

Further, the proposed reforms when considered together are likely to significantly add to the NEM's regulatory and planning complexity. For example, the AEMC envisages information from the new market for transmission hedges could be an additional input to AEMO's Integrated System Plan (ISP).

This has practical implications for consumers and the broader market. With a more complex regulatory framework, new investors in generation could be less likely to enter the market. This could tighten the supply and demand balance in wholesale markets, putting upward pressure on the prices paid by consumers.

3.2 Mistaken Conceptual Assumption

Beyond limitations with the benefits claimed by the AEMC, in support of its proposed reform, we believe the broader reform package is based on a conceptual error. The AEMC appears to suggest FTRs are a radically new instrument in the NEM and would deliver market benefits that are currently not available.

FTRs are a hedge that pays the difference between the price at two transmission nodes times a volume. Generators or others pay ahead of time for the hedge. They then receive the actual price difference for each period. Nobody 'underpins' these FTRs, as they are just a right to receive settlement residues and so are fully financed.

The settlement residue auctions which already exist in the NEM are form of FTR. When transmission is constrained and prices separate between two adjacent regions, power flows from the low-cost region to the high-cost region. This creates a settlement residue. Generators bid for the rights to the SRAs. Once they own these rights, the generator is protected against price separation between two regions. No one underpins the FTR they now own. If there is lots of price separation, the value of the hedge increases. But if there is no price separation, the hedge has no value. In either case, the hedge is fully financed by the settlement residues. The same applies, even if in a more complex manner, to FTRs in nodal markets.

In New Zealand, FTRs also include settlement residues resulting from transmission loss factors. This somewhat complicates the design of the instrument but since transmission loss factors are constant, adds little to the underlying price information. Hence, in practice, the AEMC's proposal to introduce FTRs essentially replicates inter-regional SRAs at a more modular nodal level.

We expect SRAs to achieve at the nodal level what they have achieved at the regional level. In other words, AMEC would be right in its claims FTRs can inform efficient transmission investment, if the existing SRAs already play this role inter-regionally. This is not supported by the experience of MNSPs in the NEM.

For more on the analogy between FTRs at the nodal level and MNSPs, see Box 3.1.

Box 3.1: Merchant Interconnectors and the Disconnect Between Arbitrage Revenue and Efficient Transmission Investment

The AEMC's proposal appears to assume the amount generators are willing to pay for hedges will equate to the amount of efficient investment needed across the transmission system. This is because generators can be expected to base their bids for transmission hedges on the amount by which they expect local prices to diverge from the regional reference price. The revenue raised from selling transmission hedges will then be used to

AEMO to develop its Integrated System Plan, with TNSPs relying on the revenue to build new transmission infrastructure in line with the ISP.

Effectively, the AEMC is attempting to import the merchant model for interconnection to the intra-regional level. Yet the track record of merchant interconnectors in the NEM is not something the AEMC would want to replicate at the more local level.

The theory behind merchant interconnectors in the NEM is relatively straightforward. When adjacent regions are experiencing different wholesale prices, the merchant interconnector buys power in the lower priced region and sells into the higher priced region. Unlike regulated transmission services, the owner is not guaranteed any revenue. Instead, its revenue is entirely dependent on financial arbitrage—the price difference between the NEM regions it services. Merchant interconnectors are not incentivised to 'flatten' prices across regions, like regulated transmission assets. This is because merchant interconnectors want to maintain price differentials across regions, in order to continue selling power from low priced regions to high priced regions.

In practice, there have only been three merchant interconnectors in the NEM. Of these three, two (Murraylink and Directlink) sought conversion to regulated status within a few years of coming online—they were commercially unviable. The third merchant interconnector, Basslink, has been operating since 2006. However, Basslink is known to be experiencing several commercial and technical difficulties.

The key point for the AEMC is that none of the merchant interconnectors in the NEM have raised enough revenue needed to fund efficient transmission investment. By seeking to replicate the merchant transmission model at the local level, the AEMC will be no to closer to better coordinating investment.

Further, in most markets FTRs (the rights to the settlement residues) are auctioned. The party buying the hedge bears risk on whether that was a good decision. But in the AEMC model the TNSP is selling the right; keeping the revenues; and bearing exposure to the settlement residues (between one node and the RRN) to some extent but not completely.

That is a fundamental difference. Rather than being a hedge against price separation the FTR is becoming a way of buying transmission expansion. This raises fundamental questions, including:

- Will prices be based on the efficient cost of provision, or the value to generators (the two are not identical)
- Will prices be constrained to efficient cost
- What exposure will TNSPs bear (or enjoy) from any divergence between prior cost estimates reflected in the revenues from the FTRs, and the overall costs of network expansion after the fact.

3.3 Lack of International Precedent

Overall, we want to emphasise the lack of international precedent for the AEMC's proposal achieving better coordination of generation and transmission investment. Indeed, to the best of our knowledge, no market in the world relies on the revenue raised by transmission hedging to fully plan and integrate efficient transmission investment with generation investment.

Our conclusion is best illustrated by the ongoing reform work to better coordinate generation and transmission investment in the New Zealand market. This is *despite* the existence of nodal model the AEMC is proposing to introduce to the Australian market.

The New Zealand's Electricity Commission approved the market's existing transmission pricing methodology, which took effect on 1 April 2008. However, almost immediately following the introduction of this pricing methodology, the Commission started another review of the guidelines for transmission pricing, in April 2009, which the Electricity Authority inherited when it replaced the Electricity Commission in November 2010.

The Commission started its review largely because of a significant report it received from a self-appointed New Zealand electricity industry steering group, comprising chief executives of New Zealand's major generation and distribution companies and Transpower.

Since 2010 the Electricity Authority has accorded the review of the transmission pricing guidelines as one of its top five priorities. The Authority finalised a decision-making and economic framework in early 2012. In October 2012 it proposed guidelines that would see the costs of major upgrades to the interconnection system allocated to Transpower's generation and load customers in proportion to the benefits they're expected to receive from each investment.

In addition to the intense effort the Authority has put into reforming transmission pricing guidelines since 2010, it expects the development of the actual transmission pricing methodology to take a further 18 months and then implementation to take a further 13 months. It states that new charges could apply from 1 April 2024. If the AEMC intends to pursue a similar transmission pricing methodology then it has no time to lose. It would need to devote a considerable portion of its resources to the project.

Given the importance of this problem for the NEM, we recommend an alternative approach.

4 Alternative Approaches

We agree with the AEMC there is need for market and regulatory reform to better coordinate generation and transmission investment. However, we believe international experience strongly indicates there are more straight-forward and relevant reforms than AEMC's proposals.

Below, we explain why:

- Transmission access reform requires improved central planning
- Transmission access reform requires improved transmission pricing
- Contractual coordination between generation and transmission investors could further improve outcomes, and
- Independent planning combined with competitive auctions for new transmission capacity could also improve outcomes.

4.1 Transmission Access Reform Requires Improved Central Planning

The recurring lesson from our study of international markets is the need for high-quality integrated system planning, complemented by stable long-term commercial arrangements between TNSPs and generators. Indeed, no market in the world seeks to drive transmission investment off short-term spot prices, even if indirectly through hedges.

In the NEM, until recently, the key tool for planning and coordinating transmission investment has been the application of the regulatory investment test (RIT-T). This test has attracted considerable criticism. We agree there are improvements that could be made to the design and application of the test. However, the AEMC's proposals risk diverting attention and effort from such necessary reform.

AEMC envisages revenue from transmission hedging informing transmission planning, including AEMO's ISP. However, it is difficult to see how such information would be of any use. The purpose of integrated system planning, or any form of transmission planning, is to model what the system needs to be on the basis of likely future investment needs. In other words, a good system plan is essentially a long-term future forecast, or at least a combination of long-term future scenarios. By contrast, the proposed FTRs will be short-term hedges primarily reflecting bidding behaviour of the generators already on the system. Such information will not improve system planning.

In our view, this is the wrong way to think about the planning process. Rather, the location of new investment should be guided by processes such as AEMO's ISP. In addition, the AEMC's model would still require TNSPs to submit proposed investments to the AER for assessment under the existing RIT-T. Without accompanying reforms to the RIT-T, it is not apparent how the proposed model would have a meaningful impact on investment coordination.

A more effective approach to reform—not yet considered by the AEMC—is to focus on further refinements to the RIT-T, to ensure the test is optimally aligned with AEMO's ISP. We understand some initial reform to the RIT-T has been undertaken, to reflect inputs from the ISP, but there is scope to consider this option further as a coordination tool.

One of the concerns frequently expressed by regulators is TNSPs may have an incentive to over-invest, since they face asymmetric risks: if they over-invest, the costs are socialised among the consumers, if they under-invest, the cost of system failure is driven to the system operator This is why a comprehensive reform package is needed, to ensure independent assessment of the efficiency of new investment.

In other words, there is indeed an urgent need for comprehensive review of the decision-making process that determines the following three questions:

- What transmission will be built
- Who will pay for new transmission, and
- How the new transmission will be paid for.

Such reform will not be assisted by the introduction of AEMC's proposals, and may indeed be deferred.

4.2 Transmission Access Reform Requires Improved Transmission Pricing

As the New Zealand experience with the on-going transmission pricing reform indicates, the introduction of beneficiary pays principles into transmission pricing methodology is an important component of achieving improved coordination between transmission and generation investment. To put it simply, it is necessary to decide when generators should pay for the incremental transmission investment that they induce and when transmission costs should be socialised across all users as they currently are.

There is no perfect transmission pricing methodology. For example, there has been a lot of both theoretical and practical debate about deep connection charges—where new generators pay the full incremental cost of their connection, including the cost of incremental enhancements to the interconnected core grid. This report is not the place to canvass all the arguments around deep connection charges, but rather we would like to emphasise that despite its problems, it is a valid and practical way of sending sensible locational price signals to generators. Deep connection charging is logically in line with pricing methods used in other Australian regulated infrastructure sectors (such as rail access).

There are three key differences between an approach such as deep connection charging and the AEMC's proposal to user FTRs to part-pay for transmission. Deep connection charges:

- Are based on long-term system modelling
- Can be incorporated into the overall regulatory methodology for TNSP revenue, and
- Can be targeted at specific types of new generation investment.

Deep connection charges based on long-term system modelling

Deep connection charging would be based on long-term system modelling rather than on outcomes of short-term trades

While locational price signals reflect market perceptions among incumbents, they do not accurately capture the costs and incentives for prospective generation investors. That is, locational prices only signal existing generator assessments of transmission congestion. They do not capture the risk assessment undertaken by a potential investor, deciding whether or not to enter the market.

Consider the example of a prospective generation investor following the introduction of LMP and transmission hedges in the NEM. They may be particularly interested in entering the market at a location with plentiful wind or sunshine, where they can maximise output.

But the location in the transmission system is already at capacity. The prospective investor is concerned about transmission congestion as more generators enter the market.

The prospective generation investor could buy a transmission hedge to guarantee revenue at the regional reference price. But with the potential for increasing transmission congestion, the investor is concerned about the rising cost of hedge units. Ultimately, due to the uncertainty the investor decides against entering the market.

Under the reforms proposed by the AEMC, the fact this prospective investor walks away from the market is not captured in the financial price signal. As they don't commit, they do not buy transmission hedges. The reduced number of hedges purchased at that location reduces the revenue received by the TNSP, which has incomplete information about the potential for utilitising renewable resources at the location. Consumers lose the potential benefits from optimising transmission investment and low-priced renewable generation.

Deep connection charges can be incorporated into the existing regulatory regime

Deep connection charging or something similar can be incorporated into the overall regulatory methodology to be applied to transmission. Under the AEMC's proposal, TNSPs would receive transmission hedge revenue. But as they would remain under revenue regulation, they would have to offset additional revenue by reducing regulated revenue elsewhere.

Deep connection charges can be targeted at specific types of generation investment

Deep connection charging can be targeted at new generation investments, or new generation investments, of a particular type. For example, AEMO's ISP proposes Renewable Energy Zones (REZ) as the preferred locations of new generation given the strengths and weaknesses of the existing transmission network. One obvious option to consider is whether the transmission costs of renewable generators locating within REZ should continue to be socialised, while the costs of generators locating outside the areas identified by ISP should be driven home through deep connection charges.

Without specifically advocating for deep connection charges as the solution, we think the above three reasons show that as a pathway for investigation this alternative—a comprehensive reform of transmission charging aligned with the reform of the planning process—would be more productive than the AEMC's proposed direction.

New Zealand's review of transmission pricing is also focusing on forward-looking beneficiary-pays approaches. One of the features of such an approach is it allows a more considered approach with respect to transmission charges for existing generation.

By contrast, the AEMC's proposed model would force existing generators to bid for transmission hedges. There will be no bidding between existing and proposed future generators; all bidding will be between generators already in the market. This imposes additional costs, potentially encouraging or accelerating stranded generation assets.

One of the major challenges facing AEMO is the tightening market balance between demand and dispatchable capacity. This is expected to continue, as reliance on variable renewable generation increases. The introduction of locational marginal pricing and transmission hedges risks accelerating the market exit of existing generators. This is because existing generators will need to purchase transmission hedges, to manage the financial risk from price divergence as transmission congestion increases. With increasing congestion due to new market entrants, the cost of transmission hedges will likely rise.

One of the AEMC's reform objectives is avoiding the prospect of 'lines to nowhere'. By risking the acceleration of market exit by incumbent generators, the proposed reform risks exacerbating this problem. In our view, there are strong reasons to target beneficiary-pays arrangements to new entrants who impose incremental costs on the system. A more systematic, forward-looking approach to considering transmission pricing in the context of the overall reform of the transmission investment process would allow such issues to be considered carefully and strategically. By contrast, following through with the implementation of the AEMC's proposals will make such careful and strategic consideration difficult to achieve.

4.3 Contractual Coordination Between Generation and Transmission Investors Could Further Improve Outcomes

A further option to consider as part of the comprehensive overall reform of transmission investment and pricing is whether strengthening of contractual commitments between prospective investors in new generation and transmission investors could help improve management of the overall system.

Under the existing regime, TNSPs seeking to earn regulated returns on new capital expenditure seek approval from the AER. Under the RIT-T, TNSPs are required to submit what is effectively cost-benefit analysis for any proposed investment valued at $5 million or more. The analysis considers the market problem the TNSP is attempting to address—the identified way of delivering greater market surplus to consumer. Then, the TNSP is required to assess all credible network and non-network options for addressing this need.

The AER approves the TNSPs preferred option for addressing the market need, where such an approach is deemed the optimal way to increase benefits and reduce consumer costs.

As mentioned in the AEMC's Directions Paper, there is effectively a 'first mover' problem in the existing regime. In order to demonstrate benefits from new transmission investment under the RIT-T, transmission networks need to demonstrate there is existing or committed generation capacity that could be better utilised as a result of the transmission investment. Yet for many generators, there are risks from committing to new locations before they have certainty about future transmission investment at that grid location.

A direct way of addressing this first mover problem could be to modify the RIT-T so that new generation proponents can enter contractual agreements with transmission service providers. Under this approach, generators would be committing to building new capacity at specific locations in the grid. This would allow TNSPs to approach the AER, with greater certainty about the benefits from new transmission investment. The contract would include terms penalising the generation proponent for not proceeding.

4.4 Independent Planning Combined with Competitive Auctions for New Transmission Capacity

Finally, we think comprehensive reform of transmission investment pricing methodologies would support separation of investment planning, from competitive provision of at least some new transmission services. Given the role of AEMO's new ISP, to guide future transmission planning, it makes sense to consider if efficiencies can be achieved by changing how transmission investments are implemented.

Under one further approach the AEMC should further investigate, AEMO would determine the location and capacity of new transmission infrastructure. This would be based on the system operator's assessment of future investment needs—through a process such as the Integrated System Plan, based on the market operator's technical knowledge of the power system, and extensive stakeholder consultation.

AEMO would then tender transmission investment, with tenders potentially being won by independent service providers.

Transmission projects could be tendered at an early or late stage of development. Under an early stage approach, the bidder would bear more risks on project identification and development. Conversely, it would also have more scope to innovate, potentially delivering cost savings for consumers.

Under a late stage approach to tendering, the relevant TNSP in that region could be responsible for the relevant preliminary works, producing tender specifications, and providing support during the tender, including responding to bidder clarifications and maintaining the data room with up-to-date information.

Competitive tenders for new transmission capacity have the advantage of international precedent.

- They have been used for over $25 billion of transmission investment around the world
- They have been used for over 20 years, and
- Many major markets, including the UK and the US, are moving further in this direction.

An example of the UK's introduction of competition for onshore transmission investment is in Box 4.1. The UK is not the leader in applying this model, and it should be noted that while it has developed these policies, it has not yet implemented them. Nevertheless, the UK plans to tender all major onshore transmission in the future.

Box 4.1: Case Study—UK's Introduction of Competition for Onshore Transmission Investment

In 2015, the UK Government announced arrangements to introduce onshore competition for transmission investment. The plan followed two previous reviews in the transmission investment regulatory regime in the UK, examining access reform and the integration of transmission planning and regulation. Competition for new transmission investment will apply for projects valued at £100 million (AU$180 million)—see Section 2.3.2 for more.

Under the new model:

- The regulator Ofgem will tender all new or replacement transmission infrastructure projects once the current regulatory period expires in March 2021. Until then, investment will be tendered at the regulator's discretion, on a case by case basis.
- The System Operator will take the lead in assessing network options and in some cases in developing the options. However, it will not be the decision maker. This will remain Ofgem as part of the regulatory determination process for transmission service providers.
- The System Operator will be unbundled from national grid's transmission business to avoid conflicts of interest. The UK has not moved all the way to an independent system operator as in Australia but has moved in that direction.

The implementation of these policies is still in progress. For example, sufficient parliamentary time has not yet been made available to pass the necessary legislation, and full implementation will only occur after the current price control period.

Nevertheless, the UK is following a clear policy direction towards the competitive tendering of new transmission investment.

4.5 Comparing Approaches

We agree reforms is needed to improve coordination between transmission and generation investments. In this section, we have contrasted the AEMC's more "market-oriented" approach—trying to use additional market instruments—with a more comprehensive review of transmission planning and pricing methodologies.

In our view, the AEMC approach is not supported by international experience, and at best would be a marginal bolt-on to the necessary comprehensive reform. It is also a very complex and high-cost marginal bolt on. The proposed approach risks significantly complicating, and potentially even replacing, necessary market-wide reforms.

An alternative approach of strengthening transmission planning and pricing also better responds to the reform principles outlined by the AEMC in its recent stakeholder workshops in May and June (for more, see Table 4.1).

We therefore strongly advise against proceeding with transmission access reform as proposed in the AEMC's Directions Paper. In fact, the additional regulatory complexity from pursuing the model as outlined in that paper would likely add to consumer costs.

Table 4.1: Comparing Approaches to Regulatory Reform

Principles	AEMC's approach	Focus on transmission investment and pricing regulation
Efficient generation and load investment	✘	✔
Incentivising efficient TNSP investment	✘	✔
Appropriate risk allocation	✘	✔
Technological and competitive neutrality	✔	✔
Simple and transparent	✘	✔
Safe, secure and reliable power supply	✔	✔
Coordination with other policy reforms	✘	✔
Adaptability to future market changes	✔	✔

4.6 Further Discussion

We would welcome the opportunity to further discuss our proposed regulatory reforms, to address the need for better coordination of generation and transmission investment in the NEM.

For further information on this submission, please contact **Andrew Swanson**, Senior Analyst at Castalia: Andrew.Swanson@castalia-advisors.com / 02 9231 6862.

Appendix A: New Zealand Market Overview

The New Zealand electricity sector was the subject of significant policy reforms starting in the mid-1990s. Under those reforms:

- The national New Zealand Electricity Commission, owning and operating all significant generation and transmission in New Zealand, was broken up into a transmission company, and four generation companies. One generation company was later privatised
- Municipally owned distribution entities were restructured as either community owned trusts or sold to become private sector companies. Later, they were forced to divest their retail activities. The retail activities were largely purchased by the four generation companies (a significant independent retailer went out of business during a dry year).

The New Zealand market took the vertical unbundling concept to its logical limit: not only is the sector split into the usual unregulated competitive generation and retail and the natural monopoly transmission and distribution subject to price regulation and obliged to provide open access to retailers and generators, but the distribution companies are severely restricted in their ability to own retail or generation assets. The debate about whether these restrictions should be relaxed further continues.

Initially, the development and the implementation of market design were carried out through voluntary agreements between participants and industry codes. Over time, regulatory oversight increased and the Electricity Authority now regulates runs the market and oversees market design. The Commerce Commission is the economic regulator for the transmission and distribution networks.

In the wholesale electricity pool, generator dispatch and pricing occurs on a half hourly basis. Generator dispatch is centralised with the system operator dispatching generation in bid stack order. There is full nodal pricing with 259 nodes. The pool is compulsory for all generators with capacity greater than 10MW and is a gross pool and energy only.

The system operator is a ring-fenced division of Transpower, the Government owned transmission owner and operator. The system operator is a non-profit entity with funding through market fees paid by participants generally on the basis of energy consumption. The system operator functions under contract to the Electricity Authority.

New Generator Connections

New generators wishing to connect to the transmission grid must enter into a connection agreement with Transpower covering the technical and commercial arrangements of connection. New generators only pay shallow connection charges—that is they pay for connection assets only. Connection to the transmission grid does not carry any transmission capacity or dispatch rights.

Transpower makes available a variety of planning studies and grid capability information to assist proponents of new generation projects to assess the degree of transmission constraint faced by their proposals.

Transmission pricing methodology

Transpower is required to use the Electricity Authority's Transmission Pricing Methodology (TPM) to allocate Transpower's revenue requirement via connection, interconnection and HVDC charges for its customers. The HVDC link connects the North and South Islands.

Under the TPM there are three components of the transmission charge to customers:

- Connection charges, which recover the cost of providing connection assets.
- Connection charges are calculated based on the capital, operating and maintenance costs of a customer's connection assets. It is charged as a fixed monthly sum
- Interconnection charges, which recover the remainder of Transpower's alternating current transmission system costs. Interconnection charges are calculated as the ratio of a customer's demand to the regional coincident peak demand of all customers. It is charged as a fixed monthly sum
- HVDC charges, which recover the cost of Transpower's HVDC system. HVDC charges only apply to South Island generators. HVDC charges are calculated as the ratio of a South Island generator's historical anytime maximum injection (HAMI) to the sum of the South Island generators' HAMI.

In this way, transmission charges are locational within zones and cost reflective to the extent they relate to a customers demand at the time of regional peak demand.

Appendix B: United Kingdom Market Overview

The England and Wales spot market was similar in design to the NEM. Since then the wholesale market has gone through much more rapid change than the Australian NEM. The market design shifted to a net pool in 2001. Scotland was incorporated into the wholesale market in 2004. A capacity mechanism was introduced in the electricity market reforms of 2014 together with changes to the subsidy mechanism for low carbon generation.

The details of these historical market changes in the UK are not relevant to problem of better coordinating generation and transmission investment. However, this market evolution did lead to two differences in approach from Australia which are relevant:

- The UK market has a single price zone, compared with five price regions in the NEM.
  - While the UK market does have a variety of locational price signals through transmission charges, there is no locational differences in wholesale prices.
- Since the beginning of the market, onshore generators have had firm access to the transmission network, compared with open access in the NEM. ccess in the NEM.
  - Generators agree their transmission entry capacity (TEC) in MW, based on the amount of power generators want to inject into the transmission system.
  - Connected generators pay an annual fee to use the transmission system based on their TEC[8].
  - Connection costs are partially borne by the system operator under its incentive regime, and ultimately passed on to consumers.

There are three different regulatory regimes for transmission service providers in the UK:

- Onshore
- Offshore, and
- Interconnectors.

Onshore Transmission

Since the start of the UK market, there have been three transmission owners. They have had a monopoly on developing, operating and maintaining the high voltage system within geographically defined onshore transmission areas. National Grid Electricity Transmission plc covers England and Wales. Scottish Power Transmission Limited covers southern Scotland. Scottish Hydro Electric Transmission PLC covers northern Scotland and the Scottish islands. The onshore transmission owners are subject to periodic price controls by the regulator, Ofgem.

There is a single transmission operator owned by National Grid.

[8] A 2018 rule change established TEC-lite. This allows non-standard TEC agreements. Users pay a lower TEC charge and have lower rights. The change is aimed at small generators where the double circuit connection required under the Security and Quality of Supply Standards would be inefficient.

Offshore Transmission

The government expects 15 per cent of the UK's total energy to be met from renewable sources by 2020. This implies that around 30 per cent of electricity would be from renewables.

The UK has a strong wind resource. Onshore wind generation is no longer eligible for subsidies and investment has fallen sharply. The targets will need high volumes of offshore wind generation.

UK legislation requires the ownership of transmission to be separate from the ownership of generation. Since 2009 offshore transmission owners (OFTOs) have been appointed through competitive tender. The early tenders were run under the 'transitional' regime. Transmission assets were developed by the offshore wind developer and transferred to the OFTO. Potential OFTOs bid to purchase the transmission assets from the developer and then finance and maintain the assets over a twenty-year revenue stream period. The OFTOs were chosen through a competitive tender.

Since 2014 tenders have been run under what is known as the 'enduring regime'. Offshore developers can choose whether they or an OFTO design and construct transmission assets. In both cases an OFTO will be responsible for the ongoing ownership and operation of the transmission assets.

Interconnection

The UK has a further 4 GW of interconnection with other markets through subsea HVDC links, with further interconnection under development.

Since 2014, developers have been able to choose between a 'cap and floor' regime for regulated revenue, or full exemption from regulatory requirements. The cap and floor regime limits potential losses; it is generally viewed as more attractive to financiers; and has been the preferred approach of investors. Under this approach the regulator determines which projects are eligible for cap and floor revenue recovery.

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