2 August 2019

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney NSW 1235

Lodged online via: www.aemc.gov.au

Dear Mr Pierce,

Coordination of Transmission and Generation Investment – Access Reform: Directions Paper Response

Lighthouse Infrastructure Management Limited (Lighthouse Infrastructure) welcomes this opportunity to respond to the Australian Energy Markets Commission (AEMC) directions paper *Coordination of Transmission and Generation Investment – Access Reform* issued 27 June 2019 (Directions Paper).

Summary

Lighthouse Infrastructure is an institutional infrastructure investor, whose investment mandates explicitly focus on facilitating the new infrastructure needed for Australia's future. In the energy sector a transformation is necessary to protect our economic and environmental wellbeing. We have arranged funding for some of Australia's earliest utility scale solar PV generation projects and hope to continue supporting a renewable energy transformation.

Electricity consumers are suffering elevated prices, supply insecurity, and unsustainable carbon emissions. Despite a relative wealth of natural resources Australia is addressing this energy 'trilemma' less effectively than its international peers. A solution is available; well-coordinated deployment of renewable generation and firming assets, where necessary supported by development of transmission and other shared network infrastructure.

Lighthouse Infrastructure and our peers are ready and willing to provide the necessary investment capital, but are increasingly dissuaded from doing so by uncertain network access. Prospective generators face risks arising from congestion-based curtailment, loss factor decline, and system strength obligations. These risks have escalated such that responsible managers of capital find it difficult to justify investing in electricity generation. While some investment continues, it has slowed to a pace that is well behind the level that would deliver the lowest prices, greatest security, and a responsible degree of emissions reduction. Managers of capital have other sectors and jurisdictions in which to invest; we promote solutions to these issues less out of self interest than a genuine desire to solve an important community issue.

The network access challenges facing prospective generators can be mitigated through an adjustment to the market framework. The need for reform reflects that transformation of the system introduces new priorities for market design. There are two key aspects:

1. **Transmission planning:** The first priority is to provide a sufficient volume of strong transmission connection between load centres and the optimal zones for new generation. We strongly recommend that this effort is led by central planning, rather than led by generator financial commitments as suggested by the Directions Paper. A transmission regulatory investment test should be able to capture

the benefits to consumers of new generation reasonably likely to connect, even before that generation is committed. The planning process should be conducted on a NEM-wide basis and prescribe transmission in a staged fashion so as to minimise risk that transmission is built but not used.

2. **Firm access:** The second priority is to provide firm access to new generation whose role in the system is to provide bulk energy. This will give investors the confidence to use the transmission that is available to its full capacity, providing new low cost generation supply that reduces prices and improves security. The combination of dynamic regional pricing (DRP) and financial transmission rights (FTR) proposed by the Directions Paper is a worthy suggestion for how to provide firm access, however we acknowledge that it faces significant design challenges relating to the proper identification and allocation of FTRs.

Transmission development should be identified by planning

We share AEMC's expectation that the NEM will require significant transmission development in the relatively near future. In particular transmission developments will be required whose primary role is to connect new generators to the existing network backbone, in some cases also strengthening that backbone. In this paper we will refer to transmission expansions and upgrades for this purpose as REZ transmission.

> *The NEM is currently undergoing a significant transformation… generation roughly equal to the current size of the NEM (50GW) is foreshadowed for connection to the grid over the next 10 years.*
>
> *In order to support the transition of the electricity system, the transmission network will need to develop to efficiently connect and transport large amounts of energy from dispersed renewable generation across the NEM to where consumers want to use it.*
>
> *AEMC Directions Paper, summary point 4 and section 6.1*

In the era of privatised transmission the NEM has not before faced this scale of demand for transmission infrastructure that is explicitly to facilitate new generation. As a result the framework for regulated transmission investment does not cater for it well, instead RIT-T is designed primarily for transmission that connects loads with existing generation.

> *While developing transmission to some renewable energy zones as shared transmission assets may be able to be justified through the RIT-T process, others may not. This is because renewable energy zones often involve a relatively large element of speculation as, by definition, generation has not yet connected and so is not considered committed.*
>
> *AEMC Directions Paper, section 6.1.1*

The Directions Paper proposes that transmission to connect new generation should be identified and triggered through collective purchase of FTRs by prospective generators. We anticipate that this is impractical, and that it is more appropriate for REZ transmission to be planned centrally. Our rationale for this conclusion follows:

- Prospective generators will not assemble themselves along an efficient transmission pathway unless one is set out in planning. Developers of generation will select sites entirely uncoordinated with each other, based on project-specific considerations. To collaborate in this area would be to disclose their most sensitive intellectual property. Further, generation characteristics are the key focus of generation developers, but identifying an appropriate transmission route requires consideration of network factors that generation developers are not well placed to consider. It would be more practical for central planning to identify transmission paths, having regard to suitable locations for generation and incorporating developers' views, and for developers to then identify sites along those paths.
- It is inefficient for generation developers to undertake significant development activity for a location that may never be near a transmission path. For a generation developer to make financial commitment to an FTR, it would need to have made significant progress with a specific prospective generation site. This would include identifying and surveying appropriate land, securing options to acquire that land, assessing the wind or solar resource (or other natural resource), and securing permitting. Unless or

until sufficient volumes of other compatible developments also purchase FTRs the developer's efforts are at risk of being wasted.

- The extra development time is also inefficient. When transmission access is available, a project can go from the stage of being able to make material financial commitments to being fully operational in as little as two years. It is costly and risky for a collection of developers to undertake the early development activity, acquire FTRs, then wait for several years as the transmission is developed. Additional development cost and risk, including that related to unsuccessful developments, is passed through to consumers in the cost of developments that do go ahead.
- It would be ideal if developers focussed FTR purchases in zones that are actually best suited to new generation. However this may not be the case and zones could be developed that are of poorer quality than what planners could identify. For example, in selecting locations developers may be inclined to simply follow the location selected by the first developer to purchase an FTR, with the expectation that this will be the first zone to achieve a transmission link.
- Design of transmission is not simply a case of providing thermal capacity to transmit power. For example it must consider system strength. Only central planning can sensibly optimise for all relevant factors in identifying appropriate REZ transmission and its key electrical characteristics.
- As the AEMC has identified, the NEM needs new transmission capacity relatively urgently. Central planning could identify a small number of priority developments quickly, whilst the first transmission triggered by generator purchase of FTRs would likely take ten years from now to be operational[1].

We are not aware of other electricity markets that have used the approach to REZ transmission identified in the Directions Paper[2]. By contrast we are aware of systems that have successfully used a central planning approach. Whilst having unique characteristics, the Australian system can benefit from ideas that have succeeded elsewhere.

A central planning approach can address the concern that building REZ transmission in an absence of generator commitment exposes consumers to bearing the cost of infrastructure that is not well utilised. The Directions Paper articulates this concern in its assessment of REZ transmission option 4 in which TNSPs deliver prescribed REZ infrastructure and fund it through the regulated asset base:

> *Option 4 involves transmission network service providers undertaking speculative investment in either shared network infrastructure or connection infrastructure. This would require that consumers bear the risk of this investment, which the Commission did not consider to be in their long term interest under the national electricity objective.*
>
> *AEMC Directions Paper, section 6.1.2*

We acknowledge that it is important to protect consumers from investing in unnecessary infrastructure. This risk can be thoroughly addressed through the following measures:

- Identification of candidate REZ transmission as part of NEM-wide system planning, such as the ISP, that identifies where and when new generation will be of value to the system, factoring in demand trends, expected retirements, and system reliability standards. This identification should not be led by TNSPs at a regional network level, though naturally TNSPs would make important contributions to the process.
- Cost benefit assessment of candidate REZ transmission. The assessment would be similar to the existing RIT-T but explicitly capture the benefits to consumers of facilitating the new generation identified in

[1] The FTR regime is expected to be implemented in July 2022. We anticipate that the accumulation of FTRs and decision to build a transmission project would take until 2024 at the earliest, then construction of the transmission a further c. five years.

[2] FTRs themselves are used in several markets, but primarily to allow market participants to manage nodal price separation risks rather than as the primary trigger for development of transmission to connect new generators.

the system plan. It would be appropriate for the assessment of benefits to reflect that there is uncertainty as to the degree and speed of utilisation by generators.

- REZ transmission should be staged to minimise the risk that its supply exceeds the demand for generation access. It would not be appropriate for a large number of REZ transmission projects to provide capacity all at the same time. The cost benefit analysis must take account of other REZ transmission being considered in parallel, which is feasible because the planning is coordinated at a NEM-wide level.
- Generators could be required to contribute to REZ transmission cost through an access charge, so as to reduce the cost burden passed directly to consumers. We would propose that this is a payment in return for firm network access. The shared cost recovery model devised by PIAC and described in Directions Paper section 6.3.3 has merit. The level of access charge for a particular REZ transmission project could be set as part of the regulatory investment test analysis and factored into the costs part of that analysis. Alternatively the access could be sold by auction, and the proceeds provided to consumers as a benefit above and beyond that identified in the investment test or instead allocated to underwriting the cost of the next REZ transmission development. It may even be feasible to auction the capacity at the time the REZ transmission is committed, so that if there is insufficient interest the REZ transmission could be shelved; generation developers may be prepared to offer to buy capacity on a well-defined proposed transmission path even if they are not well advanced in developing generation sites.

We reflect on AEMO and TNSP statements that the network is *inundated* with connection inquiries, and on widespread acknowledgement that there is a severe shortfall in capacity relative to the volume of new generation required. It is difficult for us to see how a diligently prepared and conservatively staged roll-out of REZ transmission infrastructure would not be utilised. This is particularly the case if connecting generators have the ability to secure firm access and the electrical path from the REZ to the regional node is of sufficiently low impedance to provide loss factor certainty. There are likely many REZ transmission possibilities that would be cost-benefit positive for consumers, and it is in consumers' best interest to start executing them promptly rather than implement a weaker development trigger that focuses on avoiding asset stranding.

We note Directions Paper recommendation 11 that a fund is established to underwrite transmission investment. Ultimately electricity consumers, who also form Australia's tax base, will pay for that fund however it is structured. Consumers would be no worse off simply funding the transmission through TUoS under the existing TNSP cost recovery mechanisms. However, if a dedicated REZ transmission fund is a more politically palatable approach then we have no objection.

Firm network access will allow efficient generation investment

Of equal importance to transmission development is that existing and new transmission capacity is most effectively utilised by generators. The open access principle on which generator access is presently based means that any generator bears the risk of their access being eroded by future generators. Erosion of access manifests in dispatch curtailment and loss factor deterioration, both of which have become high profile challenges for investors. This issue and the way in which it prevents efficient utilisation of the network for consumer benefit is illustrated in the following example.

Illustrative example of access uncertainty under the status quo

- Consider a generation zone connected to load centres by a transmission link whose capacity is 300MW 50% of the time and 200MW 50% of the time.
- Generator A connects with 200MW of renewable generation capacity. It can generate uninterrupted.
- Generator A did consider a larger plant, but it was not economic because the cost of building was such that it demanded full utilisation and any capacity beyond 200MW would be curtailed some of the time.

- Over time the cost of building renewable generation falls[3], such that only 80% utilisation is needed for financial viability. On this basis Generator B builds a further 100MW of renewable capacity near to Generator A. Generators A and B bid identically, so that when the network has only 200MW of capacity both are constrained to 67% of their capacity. Generator B achieves overall utilisation of 83%.
- With the advent of Generator B, Generator A suffers a reduction in its utilisation from 100% to 83%. It is not compensated for this loss, and had no ability to mitigate it. It is now failing to achieve its break-even business case.
- Not only has Generator A suffered, the total system has become less efficient. The incremental investment in 100MW was economic only if utilised 80% of the time, yet the incremental utilisation across the two generators arising from the additional 100MW is only 50%.
- Of greatest significance is that the likely future entry of Generator B causes Generator A not to proceed in the first place. Despite Generator A being an economically viable prospect that benefits both its owner and the system, rational investors will not support it. Even when build costs fall, neither of generators A and B are built. This is a market failure[4].

We re-emphasise that the phenomenon illustrated above does not represent a total impediment to investment in renewables. It is evident that projects with particularly strong economics can still attract investment. However, other projects that are viable on their own but cannot withstand being crowded out, cannot attract investment. Our observation of the NEM today is that the pool of developments with economics strong enough to overcome this risk is very nearly exhausted.

Certain generator classes can cope well with intermittent network access and they may not need firm access. We anticipate that the system will come to be dominated by two classes of generation asset; wind and solar that generates when its underlying resource is available, and firming plant that meets the gap between renewable output and demand. The firming plant will consist of flexible gas plant and/or storage, and is complemented by demand side response. An optimised system will coordinate generation and transmission such that little of the renewable generation is wasted through curtailment, i.e. it has effectively firm access. Firming plant will either be co-located with load centres or embedded in renewable generation zones but without firm network access, with the latter making sense because the firming role is primarily to generate when the renewables are not.

Firm access could be facilitated in a number of ways, and one of these is the combination of dynamic regional pricing (DRP) and financial transmission rights (FTR) proposed by the Directions Paper. Whilst the AEMC suggests various motivations for this reform, including preventing disorderly generator bidding behind constraints, in our view the ability to offer firm access to new generators is its most powerful benefit. Below we extend the previous example to illustrate the benefit provided DRP/FTR firm access.

Illustrative example of access certainty under DRP/FTR

- Consider the aforementioned generation zone, providing access to load centres for 300MW 50% of the time and 200MW 50% of the time. On this basis 200MW of financial transmission rights can be allocated[5].
- Generator A connects with 200MW of renewable generation capacity and is allocated 200MW of FTR. It operates unconstrained and is paid the regional reference price (RRP), so that its total hourly revenue is Rev(A) = 200MW * RRP.
- Consider again the possibility that the cost of building renewable generation falls such that Generator B builds a further 100MW of renewable capacity near to Generator A. There are no FTRs available for Generator B.

[3] Decline in the cost of building renewable generation is not merely a theoretical possibility; it is a long term trend widely anticipated to continue in the long term future.

[4] The transmission capacity available but not utilised because Generator A does not attract investment reflects an opportunity cost for the system equivalent to a stranded asset.

[5] It is important not to allocate more than this, explained later in this paper.

- When 300MW of transmission is available, both generators operate unconstrained and receive the regional reference price (RRP).
- When transmission is constrained to 200MW:
  - Both generators will bid their marginal cost[6] and these bids will set the local marginal price (LMP).
  - Generators A and B will each be dispatched at 67% of their capacity and earn 67%*200MW*LMP and 67%*100MW*LMP respectively.
  - Generator A also receives an FTR payment equal to the volume of its hedge multiplied by the price spread 200MW*(RRP-LMP).
  - The FTR payment to Generator A is paid for by an intraregional settlement residue (IRSR) that arises as a result of the 200MW for which Generators A and B are paid LMP being sold to loads for RRP and is therefore also of value 200MW*(RRP – LMP).
  - Generator A receives total hourly revenue of Rev(A) = 67%*200MW*LMP + 200MW*(RRP-LMP) = 200MW*RRP - 33%*200MW*LMP. Note that relative to the situation where Generator A was dispatched at 200MW it also saves cost of 33%*200MW*LMP. Therefore its net position is equivalent to the pre-Generator B situation identified above.
  - Generator B receives revenue equal to its marginal cost of generation. It hence makes no economic profit from generation. This is appropriate given that under network constraint the system did not need Generator B.
- Under this regime Generator A can be assured of a revenue stream that is equivalent to firm access, it is unaffected by the subsequent connection of Generator B, and it will secure the investment commitment that it would not have without the DRP/FTR regime.
- Generator B earns revenues that reflect only the marginal benefit it brings to the system. Specifically, it profits only when there is more than the 200MW of transmission capacity used by Generator A. Generator B will attract investment only when it is an efficient addition from a system perspective.

Specific DRP/FTR design comments

Pairing DRP with FTR: Financial transmission rights (FTR) are an essential accompaniment to DRP. DRP alone would shift substantial value from generators to consumers in a way that is not needed to address disorderly bidding[7], and FTR is a reasonable mitigation of this. We therefore recommend that DRP and FTR are implemented together.

FTR funding sufficiency: For DRP/FTR to succeed in facilitating investment generators must be confident that their hedges will be settled. To facilitate the most efficient investment activity this confidence should extend to the technical life of the generator, which is typically multiple decades.

The Directions Paper proposes funding hedge settlement from the IRSR created from LMP-RRP spread and that any shortfall will go unfunded. If investors have a reasonable fear of material shortfalls then FTR will be ineffective. Shortfalls will occur when FTRs exist beyond the level of physical network capacity. For example, extending the earlier example case:

- Suppose that network to which Generator A and B connect only provides 150MW of access while Generator A holds a 200MW FTR.
- The IRSR that will arise hourly is 150MW*(RRP-LMP), while Generator A seeks a hedge settlement of 200MW*(RRP-LMP). There is a funding shortfall of 50MW*(RRP-LMP).

To address this we make two design recommendations:

[6] A renewable generator will typically have zero marginal cost, but that does not alter this analysis which applies equally to any type of generator.

[7] Under DRP, constrained generators would not only suffer reduced generation volume but they would also receive a lower price than the regional price applied market-wide today, with the difference between local and regional prices arising as a settlement residue that is passed to consumers.

- Great care is required to allocate FTRs so that they do not exceed physical capacity, and generators must perceive that this system is robust. The capacity for a given generation location to access load is a function of many factors; these vary over time and may be difficult to forecast in the long term.
- In the case that DRP settlement residues exceed FTR obligations, so that there is a funding surplus as contemplated in Directions Paper section 4.5.2, the surplus should be carried forward to meet shortfalls that arise at a later time.

DRP design: In response to Directions Paper question 2, we agree that scheduled (and semi-scheduled) market participants should be settled at the RRP and non-scheduled participants should be settled at the LMP. In response to Directions Paper question 3, we support continued use of regional reference pricing.

Loss factors: Whilst acknowledging that electrical losses are a physical reality that must be accounted for in market design, the existing marginal loss factor regime is a significant impediment to efficient investment and warrants reform. Lighthouse Infrastructure has made a submission dated 18 July 2019 to the AEMC's Transmission Loss Factors rule change consultation that expands on this issue.

The aspect of specific relevance to CoGaTI access reform is that the losses created by a new generator are allocated not only to that generator but also to other generators sharing network flow paths. As a result, generation developments that are value accretive from a system perspective may not secure funding because investors are concerned by the detrimental effects of potential future generation development. In response to Directions Paper question 4, we agree that access reform should seek to address this issue and are encouraged by the suggestion that losses could be incorporated in FTRs. This may be a more appropriate solution than the average loss factor proposal.

The best solution to losses is to minimise them at a physical level. This can be achieved by providing new generation with strong transmission links to load centres through the planning process recommended earlier in this paper.

FTR features: In response to Directions Paper question 7, we suggest that:

- Duration of access products available to new generators should reflect their technical life, for example thirty years in the case of a solar PV plant.
- It appears sufficient to offer FTRs between generators and their regional reference node, so as to provide firm access to the regional price that they would expect to receive when there is no network constraint.
- Shaping to meet different generation profiles appears impractical. It is more appropriate for the owner of a block-shaped FTR to sell the component it does not require to another generator of somewhat complementary generation profile (e.g. wind and solar located nearby) such that the second party achieves partial if imperfect hedging.

Initial FTR allocation: There is a design question of whether existing generators will be allocated FTR upon introduction of DRP/FTR, and if so how scarce FTR will be allocated. We believe there are several competing principles in this aspect of design and that any regime would be contentious, and here we only seek to outline some considerations.

- There is an argument for allocating available FTR to the parties who put most value on it, which would be determined by selling the FTR through an auction or tender. However, it seems unfair to ask generators to pay to retain access that is in most cases was already near-firm upon implementation of a reform designed to encourage new competing generation.
- As an extension of that issue, it appears unreasonable to expect existing generators to compete with prospective new generators for access rights; generators existing at the time the reform is announced should have the first option and then what is left over would be available to generators coming later.
- An alternative approach recognises that most existing generators were built with a reasonable expectation of near-firm access and allocates FTR to them at no charge. An extension of this idea is that

where there is a shortage of FTR, due to a shortage of reliable underlying physical capacity, FTR would be allocate first to the oldest generators.

Cost-benefit analysis of DRP/FTR reform

It is clear that DRP/FTR reform adds complexity to the market, and we anticipate that this will be a concern for many market participants.

Whilst we are not in a position to quantify the cost of complexity, we expect that the rewards that would arise from unlocking additional efficient renewables investment would be far greater. We consider that new renewable generation with reliable network access (including a reasonably robust MLF) has a levelised cost of approximately $60/MWh, including the cost of associated REZ transmission. An optimal deployment of renewable generation would bring wholesale prices closely into alignment with that levelised cost of generation. This level of wholesale price would be materially lower than what would otherwise prevail, particularly as thermal generators retire, as evidenced recently and following the retirement of Northern and Hazelwood.

Conclusion

Investors are prepared to provide the new generation supply to deliver the lower cost, reliable and low emissions system that consumers demand. To do so the system must provide strong and firm network access.

The most powerful and straightforward reform is adjustment of the transmission regulatory investment framework to reflect the consumer benefits of opening up renewable energy zones that cannot materialise without a transmission plan. Existing and new transmission will then be most effectively utilised for generation by introducing an option of firm access, maybe by way of financial transmission rights.

This is an important but complex and far-reaching reform package and Lighthouse Infrastructure welcomes further discussion with system participants of any perspective.

Yours sincerely

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