18 May 2018

Mr John Pierce
Chairman
AEMC
PO Box A2449
Sydney South
NSW 1235

Lodged via AEMC portal

Friday,18 May 2018

Dear Mr Pierce,

**RE: EPR0052 Discussion Paper "Coordination of generation and transmission investment"**

ENGIE appreciates the opportunity to comment on the Coordination of generation and transmission investments issues paper. ENGIE, and previously International Power, has been a major contributor to the firm transmission rights consideration and later the Optional Firm Access (OFA) model. On several occasions International Power staff were also seconded to work with the AEMC on transmission congestion and the OFA.

ENGIE considers the coordination of generation and transmission investment as critically important to investors in renewable generation, as existing generators will be impacted and customers ultimately bear the costs. It is imperative that any contemplated arrangement does not unnecessarily increase costs to customers due to regulatory uncertainty and speculative projects in transmission development.

ENGIE strongly supports principles of the NEM which are economic efficiency, market based approaches and decentralised decision making.

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ENGIE's main focus in this submission is the implementation of the renewable energy zones (REZ) with some additional thoughts on energy storage.

## 1. Renewable energy zones REZ

Optimisation of transmission and generation is extremely challenging and a mathematical approach requires many parameters to be known in advance, some years in advance, to deliver a computational least cost solution. Nothing short of a central planner/common owner would approach a true least cost solution for a particular future. However the future is likely to turn out to be different than planned and there would be other major inefficiencies stemming from a monopoly provider. So least cost in the mathematical sense is a utopian concept and a practical approach dictates a solution approximating least cost.

A market-based solution is sought which supports the REZ concept and doesn't require major changes to the existing regulatory regime.

Regulatory stability is important to investors and will influence project attractiveness and costing.

It is inefficient for customers to underwrite speculative transmission development to facilitate renewable energy zones (REZ) in the hope that renewable projects are actually built.  The only certainty customers will have under this model is that the cost of transmission will increase as a result.

To optimise transmission and generation development it is necessary for the transmission and generation project costs to be known. Both of these are complex, difficult to determine, and generator project costs and considerations will not be available to the transmission network services provider (TNSP) or AEMO at the time the ISP is being developed or a RIT-T process followed. Some information is commercially sensitive and will not be disclosed to third parties to assist their planning processes.

Clearly the TNSP is best placed to determine the transmission options and costs in a specific sub-region. However it becomes less certain when dealing with usable inter-regional transmission capacities as these are a function of not only capacity of local region network elements, but also generating patterns and intra-regional constraints in other regions.

Investors in renewable projects consider a multitude of factors such as wind/solar yields and project development costs [which includes costing of equipment and transport to site, local geography and geology (ie important cost drivers in solar farm footings), transmission/distribution loss factors, grid connection charges, potential transmission constraints, wind/solar technology penetration in the region/area, potential storage in the region, other market conditions and climate change policy developments]. Since none of these project costs will not be available to AEMO or the TNSP, it is not possible for them to optimise the overall transmission/generation solution.

For a transmission augmentation to proceed under the current regulatory arrangement, it needs to pass the RIT-T. Typically TNSP will not take a risk and undertake a speculative augmentation (ie build it and risk justifying the RIT-T at some later date).

However in the event a project satisfies the RIT-T, but subsequently not all generator/load projects included in the RIT-T assumptions proceed, customers will still pay the full cost of the underutilised transmission.

ENGIE has carefully considered these issues and has developed a market based alternative to Option1, where participants are incentivised by additional price signals to seek an optimal outcome, from their perspective, but consistent with an optimised lower overall cost solution.

A fundamental aspect of this scheme is the introduction of transmission bonds to facilitate REZ network augmentation.

As a matter of principle, ENGIE supports market based, decentralised decision making approaches that are administratively simple and that don't require major regulatory changes.

ENGIE supports Option 1 for implementing the REZ. However this option may not be the most agreeable to all stakeholders as it has some potential perceived weaknesses. ENGIE has developed a variation of Option 1, with some overlap into Option 2, to provide additional certainty and visibility of the process, costs and decision making, and flexibility mechanisms by introducing the concept of transmission bonds.

<u>Key benefits of the transmission bond approach are as follows:</u>

- Seeks optimal transmission augmentation regarding location and sizing.
    - Only REZ areas with sufficient interest from projects would go ahead
    - Generator projects would be optimised across REZ zones.
        - Generators would make an assessment of a range of factors and seek the best projects across the REZ areas available to proceed.
    - Avoids inefficiencies of incremental transmission development to facilitate a REZ
- Customers will not bear the risk of speculative transmission development and stranded investments
- New entrant generators would be treated the same as existing generators regarding transmission costs.
    - They would have the transmission bond refunded and would only pay the shallow connection costs; same as other generators.
- Governments could <u>explicitly</u> subsidise transmission development.
- TNSPs would continue to follow the RIT-T process.
- Minimal regulatory changes would be required to include transmission bonds and would be confined to the RIT-T process

<u>The transmission bonds would work as follows:</u>

1. The TNSP would cost transmission augmentation to support a renewable (REZ)
2. TNSP would issue transmission bonds of sufficient value to underwrite a project. The bonds would be denominated as $/MW (notional not firm capacity).

3. Generator project proponents would seek to optimise their investments by choosing between different REZs and costs
4. Generator project proponents would purchase bonds to best meet their investment opportunities (lock in their choices)
    4.1. Transmission bonds could be secured by cash or bank guarantee
5. If the TNSP secures a quantity of transmission bonds that is:
    5.1. Less than sufficient to develop the transmission project, then the project would not proceed
    5.2. Sufficient to develop the project, then the project would proceed
    5.3. In the event that the bonds are oversubscribed
        5.3.1. The TNSP may examine potential to expand the existing project if possible, and float additional bonds to secure funding for the expanded project.
        5.3.2. Alternately the TNSP could allocate the available bonds in the order that applications were received, or in this case when the order can't be determined, randomly pick projects to allocate the available quantity.
            5.3.2.1. The allocation would be less important if there was a secondary market, where bond holders could trade the bonds between themselves to ensure the most cost-effective projects go ahead. Some projects may be willing to pay a premium to the seller to ensure their project goes ahead.
    5.4. To incentivise secondary trading of bonds and to prevent "free riders", transmission bonds would be made a prerequisite to connect a generator in a given REZ area (perhaps limited 3 years?).
6. If a generation project holding transmission bonds
    6.1. Proceeds, then the bond holder would be eligible for a refund of the bond valued at the time of purchase from the TNSP. In this way the new entrants would not be paying for transmission and are treated the same as existing generators.
    6.2. Doesn't proceed:
        6.2.1. The bond holder could attempt to sell the bond to another project.
        6.2.2. In the event that there were no buyers, they would forfeit their purchase cost of the bond (if transmission is built for a generator, customers should not bear the risk of the project not proceeding)

In the event governments were keen for a particular REZ area to be developed in their state even though insufficient number of projects was identified, they could underwrite the balance of the transmission bonds required to ensure the project goes ahead. They could then sell these bonds to subsequent project proponents over time, or just fund part of the augmentation outright.

With the exception of governments, speculative trading of transmission bonds should not be allowed.

## 2. Storage

Storage has the property of a demand when charging and generator when discharging. It is important to ensure that economic drivers on storage are conducive to reducing overall system costs. Therefore, storage should pay cost reflective distribution and transmission charges for any electricity imports. This arrangement is also equitable when compared to other loads. Storage should be treated the same as generators on the exports from the storage.

To be cost reflective, the network charge needs to be more granular than it is currently, either dynamic or perhaps conditional on some distribution/transmission system conditions. Otherwise storage risks increasing system costs by not seeing economically efficient price signals and therefore not being able to respond. Small scale storage has this very problem resulting in suboptimal economic outcomes.

The provision of other services, such as network support, ancillary services (local and central), firming services for intermittent generation, reserve capacity storage, and electricity arbitrage (between different timeframes) would be identified and offered to the market and/or networks or retailers as separate value propositions. The key challenge is to have efficient price signals, as already mentioned above, so that the mix of these services could be optimised.

ENGIE trusts that the comments provided in this response are of assistance to the AMC in its deliberations. Should you wish to discuss any aspects of this submission, please do not hesitate to contact me on, telephone, 0417343537.

Yours sincerely,

**David Hoch**
Regulatory Strategy and Planning Manager