19 January 2017

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John Pierce
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Dear Mr Pierce

Distribution Market Models Approach Paper

AEMO welcomes the opportunity to comment on the Distribution Market Models approach paper. This review is timely given the profound changes affecting electricity markets.

As the generation mix changes, the traditional model of supply following load is being displaced by a model where load is able to follow supply. As smart embedded generation and demand management becomes more prevalent, market structures will need to evolve to allow distributed energy resources to be deployed efficiently.

The energy market transformation is an opportunity to improve customer outcomes and shift towards a low carbon power system. However, it also brings new technical challenges that must not be overlooked. We need to ensure that the technical consequences of decisions are understood, and robust solutions are identified, tested and implemented in a timeframe that keeps pace with changing market conditions.

A key issue for AEMO is accessing the information that we require to be able to fulfil our statutory obligations to manage a secure and reliable electricity system and prepare forecasts of electricity demand. These issues are discussed in AEMO's report for COAG on Visibility of Distributed Energy Resources (attached).

AEMO would like to work with the AEMC and other stakeholders to develop a distribution market model that best serves the long term interests of customers. If you would like to discuss any of the issues raised, please contact Jess Hunt on 08 8201 7315.

Yours sincerely,

David Swift
Executive General Manager, Corporate Development

Attachments: AEMO response to Distribution Market Models Approach Paper
AEMO, Visibility of Distributed Energy Resources, January 2017

Attachment 1 AEMO response to Distribution Market Models Approach Paper

1. Do stakeholders agree with these definitions, or have any views on the project scope as a result of these definitions?
2. Do stakeholders support this project scope? Is there anything that has not been flagged for consideration that should be? Is there anything that should be excluded from the project scope?

The consultation paper defines “distributed energy resources” as an integrated system of smart energy equipment co-located with consumer load (such as a battery or a smart air conditioner). The definition explicitly excludes passive equipment such as a rooftop solar PV system that generates and feeds power into the grid when the sun shines.

AEMO agrees that there is an important distinction to be made between these different resources. However, excluding consideration of passive energy resources could result in a missed opportunity to explore the technical issues associated with rooftop PV and the development of an efficient, non-discriminatory regulatory frameworks to address these issues. For instance, some DNSPs prevent consumers from adding new rooftop PV once uptake on the local network reaches a certain threshold. There may be more flexible alternatives, such as requiring prospective PV owners to install smart equipment that can be remotely controlled, or establishing a framework to shift load to periods of high PV output. Local network issues arising as a result of passive energy resources may also drive new grid support services that could be provided by DER.

Accordingly, AEMO supports the proposed definitions, subject to either:

- the inclusion of certain issues associated with passive energy resources within the project scope, or
- a separate (but related) process to explore issues associated with passive energy resources.

In addition to the matters included in the project scope, the Commission should explore the underlying case for distributed markets. Historically, high transaction costs have precluded the development of distribution level markets. Technological developments are reducing these transaction costs to the extent that such markets are now feasible.

Distribution markets bring significant potential benefits in terms of empowering consumers and promoting more efficient outcomes and behaviour. However there are still barriers to achieving these benefits in practice. If distribution markets are implemented in the presence of inefficient network tariff structures, the markets could act to exacerbate distortions and increase costs from a system-wide perspective.

AEMO would not want these issues to become an excuse for inaction. However, it is important to have a robust understanding of the relevant costs and benefits in order to ensure that any reform package includes the full suite of measures to deliver benefits in practice as well as in theory.

3. Are there any other elements of a DNSP's role or current responsibilities that should be considered?

The consultation paper identifies the regulatory investment test, incentives schemes, service classification, ring fencing, and network pricing reform as relevant matters.

We suggest that there may also be merit in considering the rules and process applying to DER connections, to ensure that DNSPs' requirements and processes do not inhibit the efficient uptake of DER. The connections rules applied by DNSPs are diverse and they have the potential to strongly influence the development of DER markets.

As outlined in the consultation paper, there are many mechanisms in the NER that promote efficient non-network solutions as an alternative to network investment. In practice, these mechanisms attempt to counterbalance the incentive for networks to favour network investments that arise under the building blocks regulatory model. We note that the AEMC proposes to examine this issue as part of the Electricity Network Economic Regulatory Framework Review.

4. Are there any aspects of the regulatory framework that are not set out in sections 2.3 or 2.4 but which should be considered through this project?

The consultation paper notes that AEMO is responsible for maintaining power system security. The detailed arrangements are more complex. In practice, AEMO, DNSPs and TNSPs work together to maintain power system security.

Under the current framework set out in Chapter 4 of the National Electricity Rules (Rules), AEMO has overarching responsibility for security of the power system, including the distribution system. Among other things, AEMO must maintain effective communications and coordinate activities with transmission system operators and distribution system operators (DSOs).[1]

At the same time, network service providers and must meet the Rules system standards and network performance requirements.[2] Further, registered participants have obligations to meet their performance standards. These requirements are a key element of the overall framework for maintaining system security.

The Rules also confer on AEMO the power to delegate its power system security functions to network service powers.[3] AEMO has entered into an instrument of delegation with TNSPs in order to delegate a number functions, including the function of liaising with DSOs. This framework has the advantage of flexibility as it is relatively straightforward to reallocate roles and responsibilities between AEMO, TNSPs and DNSPs.

Given the changing technical characteristics of the power system, new challenges may emerge that are not contemplated by the existing Rules framework. In these cases it may be beneficial to amend the instruments of delegation, or potentially the Rules, to ensure that accountability lies with the party best able to manage the risk.

There may be benefits in undertaking a review of the Rules system standards and network performance requirements to ensure that they remain fit for purpose.

[1] NER 4.10.
[2] NER Schedule 5.1a and Schedule 5.1.
[3] NER 4.3.3.

5. Should the coordination of distribution systems with distributed energy resources be centralised under the direct control of one body? Or should it be devolved and performed in a tiered manner?

There is a distinction to be made between power system operations and managing distribution level markets. As the role of distribution system operator becomes more complex, it is worthwhile to consider whether the current Rules framework remains optimal. DNSPs currently manage a wide range of issues on their networks including voltage, thermal loading and power quality. AEMO's overarching responsibility for system security in electricity can be contrasted with the arrangements that apply gas, where our responsibility for managing the gas system ends at the bulk supply points.

The question of who should be responsible for managing the market platforms that support the provision of grid support services by DER involves a number of difficult trade-offs. A centralised approach maximises opportunities to optimise between different DER services, however it runs the risk of being cumbersome and slow. A devolved approach that relies on commercial platforms may permit superior products to evolve through competition rather than picking winners, but it also involves duplication and the risk of incompatibility between competing services. A well designed central platform may enable new technologies by providing low cost access to market. Alternatively, a central platform could form a barrier to entry if it becomes bound up in red tape.

In some cases, DER services may be subject to competing priorities. For example, the DNSP may seek generation to support the local network at a time when there is an oversupply of generation at the grid level, with AEMO curtailing other generators and consumers seeking to charge their batteries. Consideration should be given as to how competing priorities are managed.

AEMO also notes that with a high penetration of DER, new challenges arise in efficiently managing scheduled generators. Overall system costs could be reduced by co-optimising between DER and scheduled generators. This would likely require some form of centralised platform to coordinate efficient dispatch of all providers and services.

AEMO supports incremental reforms that keep pace with changing circumstances without locking in a particular solution. For instance, we note that the AEMC's recent decision in relation to ancillary services unbundling creates an opportunity for DER to provide ancillary services. Further incremental measures could involve:

- Enhanced monitoring and controls to promote the active management of distribution networks
- More sophisticated and transparent network planning tools to better support DER solutions
- Industry wide interoperability standards and
- Uptake of DER-based grid support services, for instance via network support contracts.

Ultimately, we support the solution that promotes the long term interests of consumers, regardless of whether it involves an expansion or contraction of AEMO's role.

6. Do stakeholders agree with the Commission's framework and these principles of good market design? Is there anything that the Commission has missed, or is unnecessary?
7. Are there any other issues the Commission should have regard to in considering possible market design options?

AEMO supports the principles of good market design set out in Box 3.2. We agree that market-based solutions are often the most efficient. However, we believe that the principles should give greater emphasis to the maintaining the security, reliability and efficiency of the power system.

The energy market transformation involves many players and is likely to involve a series of step changes. Often these step changes are driven by commercial factors rather than power system security, for instance when a large generator makes a decision to exit the market. Customers and policy makers expect power system security and reliability to be maintained throughout the transition.

The design of the electricity market needs to accommodate the laws of physics. In practice, policy makers and market designers face difficult choices given the complexity of the issues and multiple competing interests. Going forward, there would be benefits associated with a decision making framework that explicitly takes into account:

- the technical consequences of different market design options; and
- the costs and benefits of potential solutions to any technical problems.

The decision making framework should be designed to ensure that policy choices are made with a full understanding of the technical consequences of the chosen option. In many cases, an iterative process may be required.

8. Do stakeholders agree with the Commission's assessment of the technical impacts of distributed energy resources set out above in sections 4.1 to 4.8?

We agree with the technical impacts identified by the Commission, however, we would also add technical impacts associated with:

- loss of visibility,
- loss of dispatchability, and
- load volatility.

As noted in our response to questions 1 and 2, we consider that these matters should be within scope even though they are associated with both passive and smart DER.

Loss of visibility

As DER is installed behind the meter, it is often invisible to AEMO and network operators. This lack of visibility affects AEMO's ability to understand the operational impacts of DER on the power system. These issues are discussed in AEMO's report for COAG on Visibility of Distributed Energy Resources (attached).

A framework should be established to ensure that relevant data is collected and made available to AEMO and network operators. The framework should be flexible and take into account which party is best placed to collect the required information and efficiently make it

available to those who require it on an as-needs basis (taking into account confidentiality issues). A transparent process should be established to assess what information should be collected and who has access to it.

Load volatility

The technical characteristics of key types of DER (including solar PV) allow it to ramp up and down quickly, for instance, when the sun goes behind a cloud. Solar PV output within a neighbourhood is highly correlated. Further, more active customer participation means that blocks of load may suddenly shift in a coordinated fashion due to demand side management.

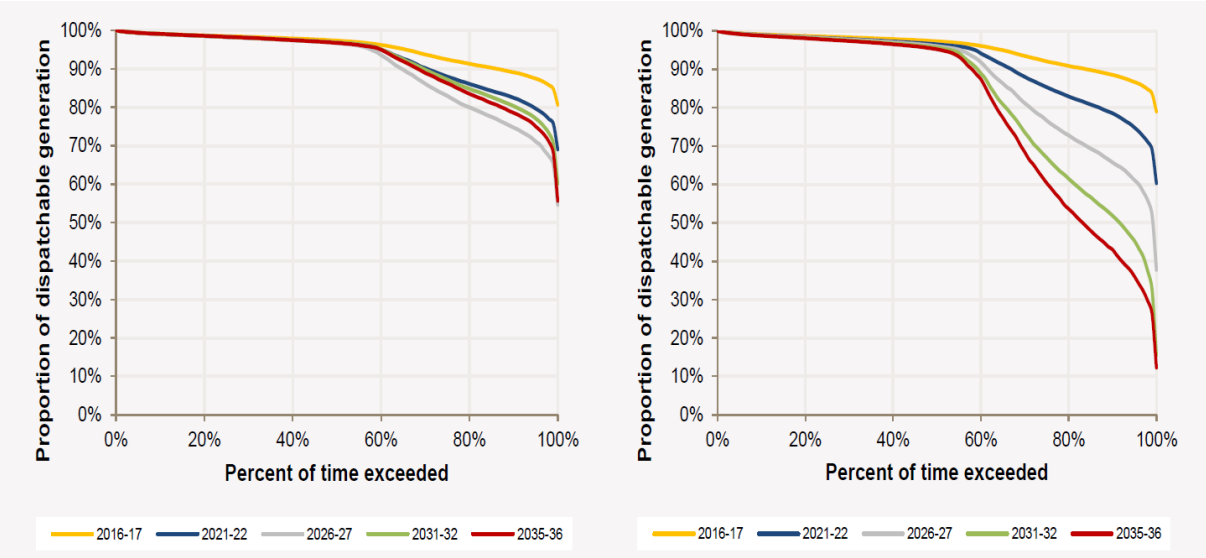
As a result, DER increases increasing volatility in load profiles can reduce the accuracy of network models and dispatch forecasts, leading to less efficient market operations (such as increased FCAS costs).

Loss of dispatchability

We note that the Commission's position is that imbalances between supply and demand is a driver of the technical issues listed in Chapter 4 rather than a technical issue in itself. We regard loss of dispatchability as an issue in its own right.

As non-dispatchable, inverter-connected generation comprises a greater proportion of total generation over the next 20 years, the visibility and control of the power system is expected to reduce (see Figure 1). In particular, if current trends continue we anticipate that rooftop PV output will exceed minimum demand in South Australia by the mid 2020s. This change in the generation mix leaves AEMO with fewer tools to manage the supply-demand balance. As the proportion of generation that can be dispatched falls, it becomes increasingly necessary to activate the demand side in order to maintain power system security.

Figure 1 Proportion of dispatchable generation in the NEM, Neutral (left) and Low Grid Demand (right)



Source: AEMO, 2016 National Transmission Network Development Plan.

If embedded generators and/or loads are price sensitive and capable of exerting a significant influence on wholesale market outcomes, then eventually some form of arrangements are required to ensure that the supply-demand balance is maintained, either by AEMO or via

devolved means. If these parties are to be dispatched, then the system operator will need to understand the relevant distribution network limitations and constraints.

9. Do stakeholders agree with the Commission's preliminary assessment of these opportunities, and possible solutions to address the technical impacts of distributed energy resources?

The Commission has identified a broad range of high level solutions; network based solutions, technical solutions, operational solutions, market based solutions and price signals.

We agree that a combination of these solutions are likely to be required. We support incremental reforms that provides flexibility for the market design to evolve in line with technological developments and consumer preferences.

10. Do stakeholders have any initial views on who should be responsible for managing these opportunities, or implementing possible solutions to the technical impacts?

AEMO has not yet formed a position with respect to this question. However, we anticipate that responsibility for implementing solutions will vary depending on the issue. For instance, responsibility for managing local voltage issues is likely to continue to lie with DNSPs whereas frequency should continue to be managed at a grid wide level.

As the new model emerges, it would be worthwhile to consider whether today's DNSPs are appropriately structured to take on new grid management and market functions.

The term distribution system operator (DSO) refers to the entity that is responsible for maintaining the distribution system and making investment decisions. The DSO function currently resides with DNSPs, however it could be undertaken independently of the entity responsible for owning and maintaining distribution network assets (the DNO). This structure could help to ensure that DER based solutions are given equal weight to network solutions in network planning decisions. Similarly, there may be questions relating to competitive neutrality if the DNSP has a role in dispatching DER and/or load management.

A market structure that features an independent DSO is still in its formative stages. The idea has been proposed, but not adopted, in the United States.[4] A recent UK Parliamentary review of low carbon network infrastructure concluded that policy makers should keep the governance of distribution networks under review, and be prepared to separate distribution networks' operation from their ownership if the joint provision of DSO and DNO functions proves to have a negative impact on consumers.[5]

[4] See, for instance, Wellinghoff, J. Tong, J. and Hu, J. (2015) The 51st state of Welhuton, 27 February 2015. The 51st State. Available at: http://www.sepa51.org/phaseII/Welhuton_51stState_Addendum.pdf and Rahimi, F. and Mokhtari, S., 2014. From ISO to DSO: imagining new construct--an independent system operator for the distribution network. *Public Util. Fortn*, *152*(6), pp.42-50.

[5] House of Commons Energy and Climate Change Committee Low carbon network infrastructure First Report of Session 2016–17, June 2016.