SA Power Networks

3 August 2018

By email: info@energynetworks.com.au

Dear Stuart and Chris,

Re: AEMO And Energy Networks Australia 2018, Open Energy Networks, Consultation Paper

SA Power Networks welcomes the opportunity to respond to the Australian Energy Market Operator (AEMO) and Energy Networks Australia (ENA) consultation paper on Open Energy Networks in Australia.

Nowhere is the transformation of Australia's energy market more apparent than in South Australia. Rooftop solar, already at the highest penetration of any state or territory, continues to grow strongly, and South Australia is now starting to lead the nation in the deployment of battery storage and the development of Virtual Power Plants (VPPs). SA Power Networks, therefore, welcomes and strongly supports the leadership shown by ENA and AEMO in developing this consultation paper.

It is apparent that the NEM will need to adapt if we are to maximise the opportunity for distributed energy resources (DER) to access and participate in the wholesale and ancillary services markets. The distribution network has a finite capacity to transport generated energy, and managing distribution network technical constraints effectively, and allocating available 'hosting capacity' efficiently to DER aggregators and demand-side market participants, will be increasingly important in the future market. If DER market access is impeded by the technical limits of the distribution network, much of the potential value to the community of customers' multi-billion dollar investment in solar PV, battery storage and other resources may go untapped.

Of the three possible future market models described in the consultation paper, the second ('Two step tiered platform') model described in section 5.4.2 appears, on balance, to be the best, although we think the characterisation of the DNSP's role in this model as 'optimising distribution level dispatch' is a little misleading. It seems to us that the DNSP's primary role in this model is to 'filter' bids to ensure that the capacity offered into the market can actually be delivered within the technical limits of the distribution network. The DNSP has no discretion in allocating network access; its role is simply to apply transparent rules agreed by all market participants. It is still the market that optimises, and AEMO that dispatches.

On the pros and cons of this model compared to the others in the paper, we note that:

- Regardless of future market models, DNSPs will need to implement substantially the same capabilities to understand, quantify and manage local network constraints in any event. DNSPs will develop these capabilities building on and integrating with existing systems and processes for network planning, operations, maintenance, outage management, load shedding and so on.

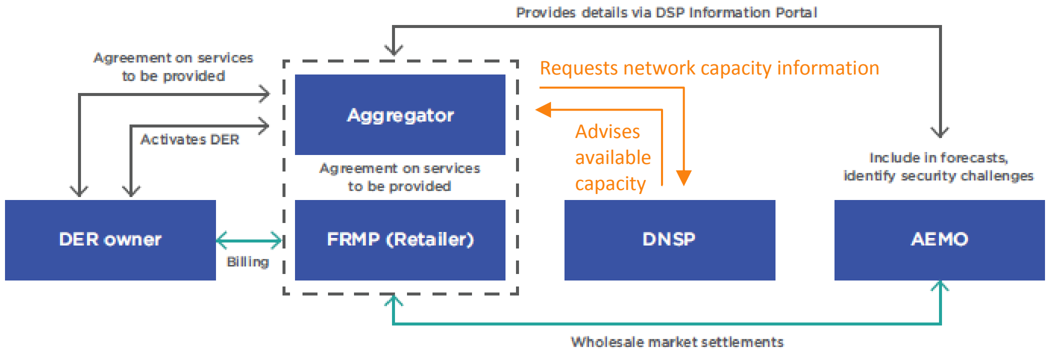
- DNSPs will need to manage a great many smaller distributed energy resources that would normally be of no interest to AEMO as they are not visible at the market level. In the first model AEMO will need to extend its reach downward, and in either model there is likely to be a significant duplication of effort and cost, and potentially a significant technical challenge in synchronising network state between the DNSP and either AEMO or the iDSO.

- The difficulty of simultaneously optimising across both transmission and distribution network constraints, as proposed in the first model (section 5.4.1), should not be underestimated. Unlike the transmission network, each distribution network has tens of thousands of nodes where constraints could arise, and the distribution network is constantly being reconfigured with hundreds of switching events each day for planned and unplanned maintenance. As noted in the paper, in practice it is likely to be impractical for AEMO to attempt to co-optimise all distribution and transmission network constraints in a single central optimisation engine, and a multi-stage optimisation process would be required. This would seem to make the first model architecturally equivalent to the third, just with the iDSO function residing within AEMO instead of a new independent entity.

- The DNSP has regulated obligations to maintain security and quality of supply for all customers. Any model where the DNSP relies on a third party (AEMO or the iDSO) to manage local impacts of DER on the distribution network will need to consider how risk is transferred between parties.

- The third model (section 5.4.3) introduces a high degree of complexity in order to mitigate one specific perceived risk: that the DNSP has a conflict of interest in managing network access given that it may also be procuring services from DER aggregators, and this conflict will lead to inefficient outcomes. We don’t consider this risk to be real, and hence we don’t expect that the additional complexity (both technical and regulatory) and associated cost of the third model would be warranted. The DNSP is not a commercial entity, nor a market participant; it is a regulated monopoly with a specific responsibility to maintain and operate the electrical network on which the market depends for the exchange of energy between producers and consumers. When it enters into an arrangement with an aggregator to dispatch DER for network support, it does not compete with other entities for access to the network, nor capture value that could otherwise have accrued to a market participant. The reverse is true; DNSPs will call on network support contracts in order to manage capacity constraints on the network that would otherwise constrain customers and market participants in their ability to export energy and create value, or put at risk their security of supply. There is no conflict of interest between a network’s use of DER and a market participant’s.

Aside from the issues noted above, we think that the paper does a good job of articulating the pros and cons of the three models presented. On the question of alternative models, we think that there is a further ‘minimal change’ option that should be explored as an interim. The approach we envisage is accommodated within the present market framework and is illustrated in the figure below, which is a variation of Figure 12 in the consultation paper.



In this approach the aggregator or VPP operator engages with the market directly as they do today, but the DNSP provides a service directly to the aggregator to advise them of any local distribution network constraints that impact on their VPP, so that they can adjust their forecasts to AEMO and/or their dispatch schedule accordingly. In practice this would be a two-way process. The VPP operator would request network capacity information from the DNSP, preferably providing a forecast of its intended operation. The DNSP could then determine, based on the prevailing condition of the network and the forecast operation of other VPPs, whether there are any local network constraints that would bind, and convey this information to the VPP aggregator(s). The VPP aggregator could then reduce its bids (if scheduled) or dispatch plan accordingly, so that it can have confidence that the VPP can provide the expected amount of power when dispatched, and will not cause local network failures.

As above, the DNSP has no role in 'optimising' the operation of VPPs in this model; optimising market outcomes is entirely a matter for the VPP aggregators, retailers and (for scheduled VPPs) AEMO. The DNSP's role is unchanged: to set export limits appropriately to ensure that embedded generation operates within the technical limits of the network and does not impact on quality and security of supply for all customers.

While we consider this to be an interim approach pending the development of a more sophisticated market model such as those envisaged in the consultation paper, we think it is potentially quite efficient. We are actively exploring this approach with VPP proponents in South Australia.

Finally, we agree that there is considerable value in considering immediate 'no regrets' actions that DNSPs and others should be taking in the short term that will help to manage the immediate challenges of integrating DER (particularly in South Australia where the market is developing rapidly) while laying foundations for future market models such as those described in the paper. Of the actions considered in the paper, building an understanding of distribution network constraints, in particular in the LV network, is a key capability gap that DNSPs must close in the short term, not just to facilitate future DER markets, but simply to manage the impacts of increasing amounts of passive DER on the network. The development of common technical standards for DER monitoring and management is also a key short-term action, as this will lead to more competitive markets and greater customer choice in the long term (e.g. by removing a barrier to a customer who owns a battery from switching from one VPP scheme to another), and reduce overall cost to industry.

Further detail on these and other issues are included in our responses to the specific questions raised in the consultation paper, attached below.

Once again we commend ENA and AEMO on this important consultation paper, and look forward to engaging further with ENA, AEMO, policymakers and industry on the future direction of the Australian energy market.

Yours Sincerely,

Mark Vincent
General Manager Network Management
SA Power Networks

Attachment 1. Responses to consultation questions

2. Path-ways for DER to provide value

1. Are these sources of value comprehensive and do they represent a suitable set of key use-cases to test potential value release mechanisms?

Yes, although we note that there is a variant of the 'active DER' use case in which DER is configured to respond autonomously to provide a market service rather than via an explicit dispatch signal sent by an aggregator, e.g. Fast Frequency Response triggered by local frequency detection. This can result in a highly synchronised response across many distributed energy resources, but with no aggregator 'in the loop' at the time. This may have a bearing on approaches to manage network constraints.

2. Are stakeholders willing to share work they have undertaken, and may not yet be in the public domain, which would help to quantify and prioritise these value streams now and into the future?

Yes. SA Power Networks has undertaken economic modelling to seek to quantify the value of DER exports and would be willing to share findings of this work.

3. Maximising passive DER potential

1. Are there additional key challenges presented by passive DER beyond those identified here?

There are potential technical challenges associated with the transition to an energy system where the primary source of generation at certain times is DER connected at the distribution network. For example, today's emergency load shedding schemes implemented by distributors operate by disconnected whole feeders at the substation. These schemes now need to take into account the level of generation occurring at the time on the feeders in question, otherwise an attempt to shed load could actually shed significant generation, exacerbating the under-supply issue.

There are also risks associated with the potential for widespread tripping of embedded generators in the event of system frequency or voltage excursions, which could cause a very significant loss of generation capacity if it occurs at a time of high solar output. This has the potential to amplify system faults that would historically have been limited in impact into events that could threaten system-wide stability. Ramp rates when systems reconnect after such a transient event also need to be considered.

2. Is this an appropriate list of new capabilities and actions required to maximise network hosting potential for passive DER?

In practice networks will need to employ a range of strategies to maximise hosting capacity, including traditional and emerging network-side solutions around voltage regulation. Of the capabilities listed, network modelling and monitoring is foundational, an essential enabler not just to active DER management and the kinds of distribution market models contemplated in the consultation paper, but to the effective implementation of network-side solutions to manage voltage or thermal capacity; without modelling and monitoring of the LV network, DNSPs cannot know where issues are emerging, cannot determine appropriate technical solutions, and cannot measure the efficacy of solutions that are put in place.

In SA we have essentially no visibility of our Low Voltage network today. This is becoming a material impediment to maintaining quality of supply within regulatory requirements and to responding effectively to the increasing number of customer enquiries arising from DER-related voltage issues. It also reduces our ability to provide timely advice to customers seeking to connect large embedded generators to the network as to the size of system the local network can accommodate. We consider it a matter of urgency to achieve a better understanding of the hosting capacity of our LV network, and visibility of its dynamic state through monitoring.

3. What other actions might need to be taken to maximise passive DER potential?

The 'static strategies' shown in Figure 7 will be important in increasing hosting capacity and encouraging greater self-consumption of locally generated energy in networks such as SA Power Networks' that have a very high penetration of passive rooftop solar PV. Our modelling shows that, for the SA network at least, AS4777 Volt-VAr response settings have considerable potential to help mitigate voltage-related issues in the medium term, if a sufficiently high proportion of customer inverters have these settings enabled. Network tariffs and other incentives that encourage shifting of load into the solar trough will help also, although tariffs by themselves cannot protect the integrity of the network during unusual events; in the absence of widespread network augmentation, networks will need a reliable 'backstop' capability to curtail excessive generation at times when this risks quality and security of supply for all customers.

There will be future innovations in the management of discretionary loads that will assist customers to maximise their own value through self-consumption, e.g. smart hot water systems or smart EV chargers that can modulate their load to follow solar output as it varies through the day. DNSPs must understand the capacity limitations of their own networks and have effective means to communicate these to the market, and provide signals that smart devices can respond to, to stimulate innovation in this space and maximise the benefits for customers.

4. Maximising active DER potential

1. Are these the key challenges presented by active DER?

Yes. SA Power Networks' own VPP trial demonstrated that the synchronised charging or discharging of multiple batteries when aggregated under central control in a VPP can cause energy flows that significantly exceed the diversified maximum demand for which the network is designed. We agree with the assessment in the consultation paper that smaller VPPs will tend to present challenges at the local distribution network level first, but if VPPs reach the scale intended for the SA Government/Tesla VPP in South Australia then they have the potential to have significant market and system-level impacts that will need to be managed in a similar manner to other large generators and loads.

2. Would resolution of the key impediments listed be sufficient to release the additional value available from active DER?

We don't find the following statement in point 1 in section 4.5 self-evident: "to reach these markets Retailers will ultimately need to make these value streams available". Under today's rules there is nothing to stop an aggregator from entering into a bilateral agreement with a customer who owns a battery to take control of that battery from time-to-time in order to offer a network support service to a DNSP, for example. The customer does not require their retailer's permission nor its involvement in the process. Their retail bill would be settled on net metered energy as usual, and they could receive a separate payment from the aggregator in return for shifting their consumption or generation patterns from time to time.

Understanding and managing distribution network constraints will be very important, just as managing transmission network constraints is very important for large generators. It is in no-one's interest if a VPP attempts to supply energy to the market and the act of operating the VPP causes voltage problems or overloads in the local network. At best the VPP will likely fail to meet its dispatch target, but at worst this has the potential to cause many customers to lose supply.

3. What other actions might need to be taken to maximise active DER potential?

Understanding and managing network constraints, and communicating these to the distributed energy market, will require investment by DNSPs in new systems, processes and capabilities.

4. What are the challenges in managing the new and emerging markets for DER?

The pace of the transition from centralised to distributed generation and the rapid emergence of new energy products and services poses challenges for regulators and rule makers in adapting the complex regulatory framework to keep up.

5. At what point is coordination of the Wholesale, FCAS and new markets for DER required?

When the aggregate amount of 'active DER' is enough to have a material impact on the wholesale and FCAS markets. In South Australia this could happen within the next 3-5 years if the SA Government battery subsidy scheme and Tesla VPP progress as intended.

5. Frameworks for DER optimisation within distribution network limits

1. How do aggregators best see themselves interfacing with the market?

No comment – a question for aggregators.

2. Have the advantages and disadvantages of each model been appropriately described?

Of the models described in the consultation paper, the second ('Two step tiered platform') model described in section 5.4.2 appears, on balance, to be the best, although we think the characterisation of the DNSP's role in this model as 'optimising distribution level dispatch' is a little misleading. The DNSP's role is more akin to 'filtering and bid aggregation/disaggregation' rather than optimisation. Its function is to 'screen' bids to ensure that the capacity offered into the market can actually be delivered within the technical limits of the distribution network at the time, and map VPP bids into a form that can be accepted and optimised by NEMDE. In this model it is still the market that optimises, and AEMO that dispatches.

We note the statements in relation to this model that it has the advantage that "DNSPs are best placed to understand, quantify and manage the limits of their own network," but the disadvantage that "DNSPs … [currently] have limited requirements for real-time management of their networks with respect to non-network assets."

We don't disagree with these statements, but they miss an important point: regardless of future market models, DNSPs will need to implement substantially the same capabilities to understand, quantify and manage local network constraints in any event in order to plan and manage the distribution network in the presence of increasing amounts of passive solar PV, flexible loads and smaller distributed energy resources that will not be visible at the market level. Thus with the first and third models proposed we would expect significant duplication of effort, with the DNSP performing a dynamic constraint management task in order to manage passive DER and small DER aggregations that are not large enough to be visible to the market, and AEMO or the iDSO performing a similar calculation of distribution network capacity in order to manage market-visible DER.

The paper states that the second model "may cause challenges in integrating NEMDE optimisation with distribution network optimisation, since they will be separate processes operated by separate entities." While there is a point of interface between two entities, this is true of the other two market models also, as both require the DNSP to communicate network constraints to another party to process. In terms of integration, we see an advantage of this model in the fact that it is entirely compatible with the existing NEMDE process; the complexity of distribution level constraints and the fact that individual resources within a VPP may map to different connection points is dealt with by a single party – the DNSP – and not exposed to NEMDE, which simply sees a small number of new (virtual) generators and loads connected to transmission connection points, and operates exactly as it does today.

The difficulty of simultaneously optimising across both transmission and distribution network constraints, as proposed in the first model (section 5.4.1), should not be underestimated. Unlike the transmission network, each distribution network has tens of thousands of nodes where constraints could arise. Moreover, distribution networks are constantly being reconfigured, with hundreds of network switching events every day for both planned and unplanned maintenance, each of which may change the mapping from NMIs to constrained nodes like transformers. Assets are constantly being replaced or upgraded as part of regular asset replacement cycles, augmentation or repair works. As noted in the paper, in practice it is likely to be impractical for AEMO to attempt to co-optimise all distribution and transmission network constraints in a single central optimisation engine, and a multi-stage optimisation process would be required. This would seem to make the first model architecturally equivalent to the third, just with the iDSO function residing within AEMO instead of a new independent entity.

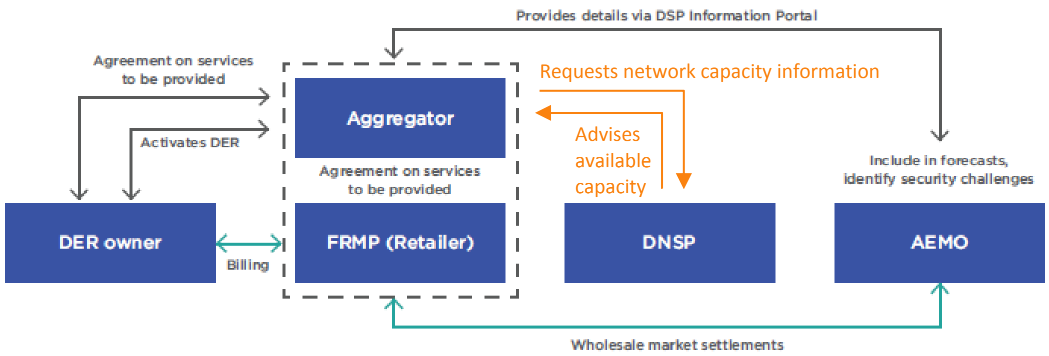
The third model (section 5.4.3) introduces a high degree of complexity in order to mitigate one specific perceived risk: that the DNSP has a conflict of interest in managing network access given that it may also be procuring services from DER aggregators, and this conflict will lead to inefficient outcomes.

We don't consider this risk to be real, and hence we don't expect that the additional complexity (both technical and regulatory) and associated cost of the third model would be warranted. The DNSP is not a commercial entity, nor a market participant; it is a regulated monopoly with a specific responsibility to maintain and operate the electrical network on which the market depends for the exchange of energy between producers and consumers. When it enters into an arrangement with an aggregator to dispatch DER for network support, it does not compete with other entities for access to the network, nor capture value that could otherwise have accrued to a market participant. The reverse is true; DNSPs will call on network support contracts in order to manage capacity constraints on the network that would otherwise constrain customers and market participants in their ability to export energy and create value, or put at risk their security of supply. Thus we see no conflict of interest between a network's use of DER and a market participant's.

3. Are there other reasons why any of these (or alternative) models should be preferred?

Aside from the issues noted in our comments above, we think that the paper does a good job of articulating the pros and cons of the three models presented. On the question of alternative models, we think that there is a further 'minimal change' option that should be explored as an interim. Three VPPs are already rolling out in South Australia (AGL's, Simply Energy's and phase 1 of the SA Government/Tesla VPP) and will be operating in the market under the present rules in the coming years. Although small from a market perspective at 5MW intended capacity each, they are large enough to potentially cause local distribution network issues at certain times, and hence we have a practical need to manage these impacts on the network in the near term, while future distribution market models are further developed.

The approach we envisage is accommodated within the present market framework and is illustrated in the figure below, which is a variation of Figure 12 in the consultation paper.



The aggregator or VPP operator engages with the market directly as they do today, but the DNSP provides a service directly to the aggregator to advise them of any local distribution network constraints that impact on their VPP, so that they can adjust their forecasts to AEMO and/or their dispatch schedule accordingly. In practice this would be a two-way process. The VPP operator would request network capacity information from the DNSP, preferably providing a forecast of its intended operation. The DNSP could then determine, based on the prevailing condition of the network and the forecast operation of other VPPs, whether there are any local network constraints that would bind, and convey this information to the VPP aggregator(s). The VPP aggregator could then reduce its bids (if scheduled) or dispatch plan accordingly, so that it can have confidence that the VPP can provide the expected amount of power when dispatched, and will not cause local network failures. We consider that offering this kind of service will enable VPPs to access more of the available network capacity than the alternative, which is for the DNSP to impose static 'safe' export limits to individual VPP customers through its connection agreements that are low enough to allow for the worst-case VPP dispatch scenario. We are actively exploring this approach with VPP proponents in South Australia.

It is important to note that the DNSP has no role in 'optimising' the operation of VPPs in this model; optimising market outcomes is entirely a matter for the VPP aggregators, retailers and (for scheduled VPPs) AEMO. The DNSP's role is unchanged: to set export limits appropriately to ensure that embedded generation operates within the technical limits of the network and does not impact on quality and security of supply for all customers.

While we consider this to be an interim approach pending the development of a more sophisticated market model such as those envisaged in the consultation paper, we think it is potentially quite efficient. One limitation compared to the models presented in the consultation paper is that the DNSP has no visibility of the 'value' of the network access being requested (e.g. the bid price to AEMO), and so when two or more VPPs are seeking to dispatch on a constrained network segment the DNSP can only allocate available capacity on an equal basis. If only one of the VPPs is dispatched, the capacity allocated to the others will be unused. In practice we would expect VPPs to have similar costs, and hence bid in at similar prices, so a simple 'equal sharing' approach, while imperfect, may be a reasonable approximation. This approach would, however, require some mechanism to ensure that aggregators do not habitually 'over-reserve' network capacity that they do not expect to use, in order to limit capacity available to competitors; there would need to be some incentive to provide forecasts that are accurate.

6. Immediate actions to improve DER coordination

1. Are these the right actions for the AEMO and Energy Networks Australia to consider to improve the coordination of DER?

We agree with the set of immediate actions set out in the consultation paper. Of these, we place particular importance on building an understanding of distribution network constraints, in particular in the LV network. This is a key capability gap that DNSPs must close in the short term, not just to facilitate future DER markets, but simply to manage the impacts of increasing amounts of passive DER on the network. The development of common technical standards for DER monitoring and management is also a key short-term action, as this will lead to more competitive markets and greater customer choice in the long term (e.g. by removing a barrier to a customer who owns a battery from switching from one VPP scheme to another), and reduce overall cost to industry.

2. Are there other immediate actions that could be undertaken to aid the coordination of DER?

DNSPs should continue to progress the introduction of more cost-reflective network tariffs, as this will encourage more efficient use of available network capacity, increasing the hosting capacity 'headroom' available for active DER to trade energy in the market.