2 August 2018

Mr Warwick Anderson

General Manager, Network Finance and Reporting

Australian Energy Regulator

Via email

CC: Adam Petersen, Director

Dear Warwick

Re: CCP14 advice to the AER in relation to SA Power Networks' proposed approach to managing the increasing penetration of embedded generation on the SA distribution network

I am writing in relation to the recent written advice from the Consumer Challenge Panel CCP14 to the AER, published on the AER website in the document titled *Response to the SA Power Networks (SAPN) approach to the challenges of the high penetration of embedded generation as part of their 2020-25 Regulatory Proposal early engagement*, dated June 29, 2018.

We welcome CCP14's considerable interest and engagement on this aspect of our regulatory proposal. We are always seeking to improve the way we communicate and consult with our customers and stakeholders, and CCP14's feedback on our stakeholder engagement sessions has been constructive and insightful.

In its advice, CCP14 has raised a number of questions and concerns in relation to our proposed Low Voltage (LV) management strategy, that is, our proposed approach to managing the forecast uptake rates of Distributed Energy Resources (DER, i.e. rooftop solar PV and battery storage) in South Australia from 2020 onwards, which will exceed the technical capacity of the network in many areas.

This is an important area because the industry is undergoing its most significant transformation since its inception, and if we do not respond accordingly and adapt, the distribution network may become a bottleneck that severely curtails the ability for customers and new energy services providers to participate in the market and contribute effectively to the energy system in South Australia. As we respond to this transition we need to ensure that any changes we make to the way we manage and operate the distribution network are in the best long-term interests of all customers in South Australia.

To recap, in our public workshops we characterised our future options in this regard in terms of three possible approaches:

1. 'No constraints': we can continue to invest in increasing the capacity of the network to allow customers to connect DER and export energy to the grid at any time. *Note that this investment would include spending on both network and non-network (market-based) solutions*. In this approach all customers bear the cost of increasing network capacity so that those customers with DER can get the most benefit from their systems. As constraints typically occur infrequently, this approach tends to lead to a reduction in network asset utilisation.

2. 'Static limits': when part of the network reaches its technical capacity we can require all new systems connected to the grid in that area to be configured as 'zero export' – i.e. customers can generate energy to use in-house, but cannot feed energy into the network. This would obviate the need for expensive network capacity upgrades, but reduce the value to those customers with DER, as they could not access a feed-in tariff or participate in network support schemes or Virtual Power Plants. Hence it is more of a 'causer pays' approach, although our economic modelling also shows that it results in a loss of value to all customers in the long term through loss of wholesale market benefits. This approach minimises network expenditure, but is inefficient as the value from DER is constrained all year even though the technical constraints are only present for a fraction of the time.

3. 'Dynamic limits': we can offer dynamic export limits to small generators and virtual power plants, as we do today for generators larger than 200kW. This would enable us to signal the true capacity of the network on a locational and time-varying basis, so customers exports would only be limited at those times and in places where there is a capacity constraint. This is our proposed approach, as our modelling shows that it increases utilisation of existing assets and provides the best long-term outcome for all customers (both with and without DER) under a range of possible future scenarios.

Our proposal includes expenditure in two areas:

1. Visibility of the LV network: whichever approach we take, maintaining security and quality of supply in a high-DER network requires a base level of monitoring and visibility of the LV network that we do not have today.

2. Dynamic export limits: we need new systems and interfaces to offer dynamic export limits to VPP operators and small embedded generators.

We note that CCP14 has prepared its advice to the AER on the basis of views formed during our stakeholder 'Deep Dive' workshops, primarily the Future Network workshop on 31 May. CCP14 prefaces its advice with the following statement: "CCP14 has received a volume of information from SAPN since this matter has been raised with them. This provides insight into the consideration and assessment made by SAPN as part of their work in developing the position presented at the workshops. CCP14 appreciates this provision of this information, however given that we are assessing SAPN's public consultation process, our commentary is based on what has been presented and discussed in those forums."[1]

[1] CCP14 advice to AER, page 3.

While we make every effort to explain our plans and spending proposals in our public stakeholder workshops as clearly as possible, we recognise that these are complex issues and we are limited in the level of detail we are able to present in these public forums, which must suit a range of stakeholders, many of whom do not have the level of expertise of CCP14 members. In light of this, SA Power Networks engaged with CCP14 after the 31 May workshop to provide further details on our approach and to address specific questions raised by CCP14 members arising from that workshop. We:

- Provided a seven-page written response to specific questions raised by CCP14 on 27 June, along with a number of supplementary documents describing aspects of our approach to assessing options in this area in considerable detail
- Met with CCP14 on several occasions to answer questions in person
- Facilitated a teleconference between CCP14, the AER and HoustonKemp, the economic consultant that has advised us on the economic models we use to assess long-term economic outcomes of different approaches to DER/network integration.

We appreciate that CCP14 was unable to consider and incorporate this material in their advice to the AER and thus we repeat it in this response, and will continue to engage with stakeholders, CCP14 and AER to build their understanding of these issues.

In relation to CCP14's key points and specific advice to the AER:

1. CCP14 makes a number of statements calling into question SA Power Networks' reliance on AEMO forecasts of solar PV and battery uptake in South Australia. On this matter:
    - We are not aware of any other forecasts that are more accurate than AEMO's, which are prepared by CSIRO with input from the foremost experts in Australia in this area.
    - We also note that in our 2015-20 regulatory determination, the AER rejected alternative forecasts put forward in our regulatory proposal and directed us to rely on AEMO's forecasts[2].
    - Hence we intend to rely on AEMO's latest (July 2018) forecasts unless directed otherwise by the AER.
    - That said, we fully understand the level of uncertainty in any future forecasts at this time, which is why we are running sensitivity cases across a range of forecasting assumptions to ensure that the strategy we put forward is robust to a wide range of possible futures. This future uncertainty is a key driver of our preferred approach, which is all about preserving optionality, minimising the risk of stranded investment and investing in the systems we require to engage with the market to maximise use of third-party, non-network solutions in lieu of network asset investment wherever possible.

[2] *PRELIMINARY DECISION, SA Power Networks determination 2015–16 to 2019–20, Attachment 6 – Capital expenditure*, p 6-45, AER, April 2015

2. CCP14 is concerned that we have given insufficient consideration to the opportunity to contract with third-party energy services companies to resolve distribution network issues arising from the connection of DER. We have, in fact, given considerable consideration to this, but we fully accept that this was not clear in the way we presented our approach at the Deep Dive workshop. We have been actively investigating these opportunities over the last two years and continue to engage with the developing market for new energy services providers to seek opportunities for such solutions:

    - We have funded a 100-customer VPP trial in Salisbury specifically to test the capability of customer-owned batteries to support the network.
    - We are working with AGL, Simply Energy and Tesla to identify opportunities to demonstrate the network support capabilities of their new VPPs in South Australia.
    - We have been developing an internal process to engage with the market for non-network alternatives to network upgrades that fall below the RIT-D[3] threshold, and will be issuing a Request for Proposals in the coming weeks in relation to several upcoming network constraints, including constraints arising from high penetration of DER.

    While we expect to make increasing use of these kinds of market-based solutions in future, they will not be applicable in all circumstances. Many of the constraints that will drive the need for network augmentation in future will arise at the local Low Voltage (LV) circuit or LV transformer level due to excess local generation and, in particular, due to the coordinated operation of batteries that are enrolled in VPPs responding to external signals such as market price spikes, or responding automatically to frequency disturbances. It will not generally be possible to procure network support services from customers or DER aggregators to resolve these kinds of localised constraints, because the only demand-side resources available to provide network support at that level will be the local distributed energy resources connected to the circuit in question – i.e. the same resources that are the source of the constraint[4].

    It is worth noting that our strategy in general is to make use of market-based solutions in lieu of network-side solutions wherever possible (to the extent this is prudent and efficient) as this generally gives increased optionality and ensures our investment choices are robust to a broad range of possible futures. Investment in modelling and monitoring in our LV network is a pre-requisite for effective engagement with the demand-side market, as it is what will enable the publication of 'opportunity maps' to inform the market where capacity constraints exist.

    Our non-network strategy is also evident in our proposed approach to end-of-line and mid-line monitoring in the LV network, which is not to invest capex in deploying SA Power Networks monitoring devices into the network (or to the customer meter board), but rather to invest in setting up a market interface that will enable us to engage with retailers, metering providers and other parties who have smart meters and other devices able to provide the data streams we

[3] Regulatory Investment Test-Distribution – a rule that requires us to test the market for non-network solutions before undertaking any major capital investment in network assets. See *Final decision, Regulatory investment test for distribution and application guidelines*, AER, 23 August 2013.

[4] Such a network support contract would create a perverse incentive for customers to install DER on a circuit that is already capacity constrained, in order to receive an incentive not to exacerbate the issue. Meanwhile the cost of this inefficient incentive would be borne by those customers without DER.

require. We have recently issued an EOI to smart meter providers and retailers to test the market for such third-party data services.

3. While we tried to explain during the Deep Dive workshop that our dynamic export limit is just one of a range of strategies we are employing to increase DER hosting capacity, we recognise that this message may have been lost. To be clear, we have been and will continue to pursue a range of complementary approaches informed by our modelling:

    - We have already moved to mandate inverter Volt-VAr response settings (in the December 2017 revision of our connection standards), as our modelling shows that this can be very beneficial in the long term in mitigating voltage related issues.
    - We are already advancing tariffs through our draft 2020-25 Tariff Structure Statement (TSS) intended to encourage shifting of load into the daytime solar trough[5].
    - We are engaging actively with incumbent and emerging energy services providers to identify options for market-based solutions.
    - We continue to evaluate new products and technologies to ensure we can access the most efficient grid-side solutions.

    These measures will help to increase the hosting capacity of the network, but our modelling indicates that they will not be sufficient to prevent emerging local constraints if we are to continue to allow DER to connect to the network at forecast uptake rates. Unless we add significant network capacity we require a means to manage energy exports are certain times as a necessary backstop to ensure we can met our obligation to provide safe, secure and reliable access to the network for all our customers across a broad range of operational scenarios.

4. CCP14 raises a number of questions on the depth and breadth of the modelling we have used to inform our views, and we accept that the level of detail we were able to convey during the Deep Dive workshops was not sufficient for stakeholders to form an informed opinion on the rigour of our approach. We have provided considerable additional detail on the methodology we have used and the range of options we have explored to CCP14. In summary:

    - We engaged UK consultant EA Technology to undertake the modelling that underpins our approach. EA Technology were selected through a competitive tender process as they are recognised as leaders internationally for their expertise in this area. The modelling is extremely rigorous and takes into account a broad range of factors, including the mitigating impact of battery storage in absorbing some solar during the middle of the day, as well as the impact of local inverter Volt-VAr response, and the potential impact of tariff changes in shifting loads.

[5] We note that tariffs, which are based on long-run marginal cost (LRMC) are effective in sending long-term price signals that encourage efficient investments, and help to balance supply and demand day-to-day, but are not intended to manage short term, localised constraints; tariffs and price signals cannot 'keep the lights on'. This is the case today in the way transmission network constraints are managed in the wholesale market.

- We have considered a wide range of possible remediation methods including non-traditional methods such as grid-connected batteries. We continue to work with stakeholders to explore opportunities for market-based solutions.

- We have used a formal risk assessment framework as part of our analysis, and provided a summary risk assessment. Our Regulatory Proposal will include more complete documentation of the risk assessment undertaken for each option considered.

5. CCP14 recommends that SA Power Networks makes greater efforts to engage with the wider DER market on these matters. We agree.

    - As noted above, we are already actively engaging with AGL, Simply Energy and Tesla in relation to their new VPPs in South Australia, both in terms of ensuring effective grid integration and in terms of exploring opportunities to use these systems for network support. We are a financial partner in Simply Energy's ARENA-funded VPP project and have been working closely with both Simply Energy and platform provider Greensync during the design phase of this project over the last 12 months.

    - We hosted an industry workshop in Melbourne on 17 May which brought together key stakeholders from across the DER industry, including retailers, solar and battery companies, inverter manufacturers, technology vendors, new energy services companies, platform providers and aggregators, to discuss and seek industry advice on future approaches to grid integration of DER and VPPs. At that workshop we committed to following up with a formal consultation paper to industry, and a second workshop. We are about to release the formal consultation paper.

    - Reflecting on CCP14's recommendation, we are convening a new 'DER integration' working group comprising key DER industry stakeholders, to provide a forum to listen and seek industry feedback on this aspect of our Draft Plan when it is released in early August. The terms of reference of this group are currently being drafted, but it is intended to be complementary to both the technical group convened for the Melbourne workshop, with which we will continue to engage through the consultation process already in train, and established stakeholder groups such as the Renewables Reference Group. We think that this will fill a gap in our consultation process identified by CCP14.

6. CCP14 has commended SA Power Networks on our approach to stakeholder consultation, and recommends that we expand the scope of our engagement with broader stakeholders in the community. We agree. We consider that our customer engagement program for our 2020-25 Regulatory Proposal has been comprehensive, so far involving nearly 3,000 participants across 43 workshops and other activities around the state since the program commenced in February 2017. We will continue to engage openly with as broad a range of stakeholders as possible as we continue to progress this program, the next major milestone being the release of our Draft Plan in early August. Our approach to managing increasing DER in the grid will continue to be a significant area of focus in our engagement program.

We are also engaging actively with the South Australian Government on the question of DER integration. The Government's vision is that VPPs will play an important part in South Australia's future energy mix and hence it is supportive of prudent investment in measures that will ensure that the South Australian distribution network does not become a bottleneck that constrains the ability of VPPs to operate to their full potential and thereby constrains the development of competition in the NEM.

7. CCP14 has recommended that SA Power Networks undertake further work to refine its proposed technical approach and the associated expenditure, giving particular consideration to efficient staging of work. We agree with this. At the Deep Dive workshop we made it clear that the capex and opex estimates were preliminary and a 'work in progress' as we were in the process of evaluating variations on the proposed technical approach, as well as refining input cost estimates with our consultant KPMG and others.

   A significant component of both the capex and opex associated with the solution presented in the Deep Dive is associated with the cost of building and maintaining an accurate electrical model of our urban LV network (some 17,000 LV transformer areas) in order to accurately calculate voltage and thermal limits. An alternative approach that shows considerable promise is one based on building a more abstract 'template'-based model of our low voltage network initially rather than a fully accurate electrical model, an approach that has been employed by Western Power Distribution (WPD) in the UK. WPD found that accurate modelling of around 10% of the network, sampled appropriately across different network types, combined with monitoring of the sample feeders, was sufficient to estimate the performance of the remaining 90% of the circuits on the network to 80% accuracy.

   Adopting a template-based network model for our proposed dynamic export limit scheme would increase the amount to which customer DER would be curtailed, as we would have to allow sufficient headroom to allow for the inaccuracy of the model. This would result in a lower benefit relative to the option presented in the Deep Dive.

   The template-based approach is, however, a lower-cost approach. The differences in costs compared to the full LV model presented in the Deep Diver workshop would be:

   - Costs associated with building the LV model are significantly reduced, as we are only auditing and modelling 10% of the network in detail, with work staged in priority order through the period. However, as part of this solution we would also put in place business process changes to enable field crews to capture network data as part of normal maintenance works. This would progressively improve the accuracy of our LV network model in the remainder of the network over time, ultimately reducing the cost to transition to a full network model in future should this be required.

   - Opex costs associated with procuring end-of-line and mid-line monitoring data from 3rd party data providers are similarly significantly reduced, as we will target monitoring to the sample circuits. Costs of the backoffice systems required to store and process this data remain mostly unchanged, but reduce slightly due to lower data volumes.

   - Costs associated with DER registration and information storage and the interface to external systems (API) are unchanged.

- There is a reduction in costs for the active DER management (dynamic export limit control) component due to a reduction in complexity. Some functionality that may be required to enable future distribution market models would be deferred until after 2025.

- Costs for business process change and program management would be unchanged.

This solution would require expenditure in the 2020-25 period in the order of $37 million in capex and $9.5 million in opex, compared with $57 million capex / $26 million opex for the solution presented in the Deep Dive.

We are still working on quantifying the reduced economic benefit of this simplified solution. However, given the significantly lower cost of this solution we expect the cost:benefit ratio to be better than the solution we proposed in the Deep Dive workshop across all sensitivity cases. That being the case, we will put forward this approach as the preferred solution in our Draft Plan.

Importantly, this approach retains the optionality to progress to a full network model in future should this be warranted. In practice, we would re-assess towards the end of the 2020-25 period whether there is a case for further investment in 2025-30 to improve the capability of the system. This would also be informed by the requirement, if any, to support new 'distribution market models' being contemplated.

8. CCP14 noted that 'the costs to customers… have not been articulated'. We agree that any consequential cost to customers must be taken into account in considering the economics of any future approach. Our view is that the cost impact on customer equipment is likely to be immaterial in most cases, as the necessary capabilities are either already present in customer equipment (e.g. the capability to set an export limit is already a requirement of AS4777[6]) or will be ubiquitous in the timeframe we are proposing to enable this (e.g. inverters from leading brands are increasingly enabled with remote communication interfaces as standard, to support manufacturer web portals and apps – in particular for battery systems as this is necessary to implement VPPs). In cases where the customer would face a marginal cost (e.g. because they don't have an internet connection), the customer would be able to choose whether the cost of gaining access to the dynamic export limit scheme is warranted in terms of the additional value it may unlock from their system.

   At our industry workshop on 17 May we commenced the process of engaging with manufacturers to determine the potential cost to industry to support our proposed API. Initial feedback was that these things are technically straightforward for the manufacturers, and they already support similar functions in other markets. For example, Germany has had a mandatory requirement for several years that all solar inverters must support an export-limiting signal from the distribution network. We will continue to explore these matters as we continue our technical consultation with industry.

[6] All inverters must at least support a basic gross output limit, and leading brands like Fronius, SMA, Enphase and Solar Edge already support net export limiting with the addition of a net output meter.

9. In item 8 on the final page of its report, CCP14 recommends that SA Power Networks "*consider a connection agreement framework that supports the intent of 'causer pays'….*" South Australian legislation does not allow us to apply network augmentation charges to Small Embedded Generators, nor can we apply network tariffs to exported energy. The AEMC has recently considered these issues, and its final report on the network regulation framework review will comment further, but we do not anticipate any change to the rules in this regard. Of the options we have examined, we consider that our proposal to implement dynamic export limits strikes the best balance between enabling customer choice to connect DER and ensuring that this does not drive additional costs on to other customers.

10. Finally, we would like to clarify a number of related issues raised in the CCP14 report in relation to our proposal:

    - SA Power Networks has a regulatory obligation to maintain the quality, reliability and security of the South Australian distribution network. This is the primary driver for the proposed investment in managing the impact of DER connected to the network.

      Our challenge is to determine the most prudent and efficient investment strategy to continue to meet this obligation as we exceed the technical limits of the existing network assets, and our modelling indicates that this will be through enabling dynamic export limits, rather than extensive investment in increasing network capacity or imposing static export limits.

      We have based our comparison of options on the guidelines used in the AER's RIT-D framework. The RIT-D requires networks to take a 'whole of market' approach to assessing the costs and benefits of network investments, rather than focusing on the costs and benefits to any individual party, and is intended to ensure that investment decisions are in the long-term interest of consumers.

      SA Power Networks also has a regulatory obligation to co-operate with and assist AEMO in maintaining state-wide power system security. Customers have connected their DER to the SA distribution network in accordance with State and National Electricity legislation. If the aggregated impact of this DER has the potential to affect system-wide security then clearly SAPN has a responsibility to cooperate with AEMO to address this issue. To suggest that "*…consumers would reasonably expect this be resolved or at least 'owned' at government or regulator level*" ignores SA Power Networks' regulatory obligation in this regard. While we will continue to engage with the SA Government and regulators on this matter, this does not relieve us of our obligation.

      One of the key new capabilities we require to manage distribution network constraints, namely an interface that enables us to send an export limit signal to a generator or VPP aggregator, is the same technical capability that AEMO would need to implement PV feed-in-management to manage system-wide security of supply risks at times of very high solar output. On the basis of AEMO's recent work on system security impacts of high levels of solar PV we think it is likely that AEMO *may* require this facility in South Australia prior to 2025 in order to manage contingent events. Hence we envisage that AEMO may, in future, direct us to undertake 'emergency generation shedding', just as they can direct us to undertake emergency load shedding today. However, it is important to note that our

business case for dynamic export limits *does not* rely on any such assumed requirement from AEMO; our analysis is based entirely on distribution network considerations. The potential to provide a valuable system security service to AEMO in future is, therefore, a consequential benefit of our preferred approach. There is no value attached to this benefit in our economic comparison.

- We are not seeking to advance any particular future 'distribution market model' as contemplated in the recent ENA/AEMO *Open Energy Networks* consultation paper[7]. As described above, our concern is managing the quality and security of supply for all customers. We are not proposing a new service, rather to extend a capability that is already used to manage the impact of large embedded generators down to small generators and VPPs, as these are becoming the dominant drivers of quality of supply issues. That said, we are supportive of the work ENA and AEMO are doing to consider the long-term evolution of the market for new energy services and the critical future role of distribution networks in enabling distributed energy resources to access the wholesale and ancillary services markets. We note that the systems we propose to establish to understand and actively manage capacity in the low voltage network are necessary foundations for such markets to operate efficiently, under any future market model. There is no risk that these investments will be made obsolete or stranded, however the market evolves.

- Our proposed approach is not about SA Power Networks directly controlling customer equipment in the same way that networks like Energex control water heaters, pool pumps and air-conditioners. It is entirely about enabling customers and energy services providers to operate their distributed energy resources within the technical limits of the local distribution network so as not to cause supply issues for themselves or their neighbours. We are proposing to put in place the systems and market interfaces we require to:

    - Publish real time limits under which DER and VPPs can operate

    - Generate and publish hosting capacity information essential to making informed investment decisions by all parties including SA Power Networks, customers and energy service providers

    - Identify areas of the network where issues are emerging and target solutions to those

    - Contract with third parties that have customer-side resources under their control to provide network support services – not for us to control those resources directly

    - Execute efficient passive strategies such as static voltage control and price signals where possible to increase the base hosting capacity of the network.

We have provided AER with further information that relates to these and other issues raised by CCP14 in their report in separate documents.

[7] *Open Energy Networks, consultation Paper*, AEMO and Energy Networks Australia, 2018

We trust that this material is of help in clarifying the issues raised in the CCP14 report, and look forward to the opportunity for continued dialogue with the AER to answer any further questions arising.

Yours Sincerely,

Mark Vincent
General Manager Network Management
SA Power Networks