Attachment: SAPN Detailed Feedback

1. Consultation on the proposed remote disconnection and reconnection requirements for distributed solar generating plants in South Australia.

We support the need for an emergency generation shedding capability for rooftop PV, but consider that further consultation is required on the best technical approach, and because of this, the proposed timeframe is unlikely to be achievable. A solution which provides a transition pathway to export limit requirements (Consultation Paper 2 – Export limits) should also be encouraged.

- The terminology infers a physical disconnection, it should be made clear that this could be equivalently achieved by reducing PV output to zero.
- AEMO has already confirmed that they will instruct the DNSP to coordinate all disconnection and reconnection orders for DER connected to their networks. It should be made clear to industry that SAPN will be the party to which registered agents will need to integrate.
- In this context, it may make more sense to simplify the process by passing the registered agent responsibility on to SA Power Networks and we can then manage a registration process through the connection's approval process (better upfront than after the fact). We also can't have a situation where another party is independently directing generation connected to our network without our ability to coordinate actions and manage risks to distribution network integrity.
- Although we are highly supportive of market led solutions and enabling choice, we also need to reduce cost, complexity and risk overall by ensuring that proposed solutions meet certain detailed requirements and that these control mechanisms can be reliably accessed via the DNSP under emergency conditions. To this end, we believe a complete, technology agnostic, technical specification should be developed in consultation with industry to provide this guidance. It will be necessary to provide sufficient requirements to industry to ensure that market-developed solutions are of sufficient quality and do not compromise cyber or system security via their implementation.
- Further, although there might be proprietary mechanisms deployed by solution providers (registered agents) to achieve this requirement, the interface between these parties and the DNSP to manage this capability must be standardised e.g. API in order to ensure an appropriate level of dependability, predictability and cyber security.
- The industry should be encouraged to consider solutions which provide a transition pathway to meeting the separate requirements regarding dynamic export limiting. SA Power Networks would prefer to see an integrated approach based on an IEEE2030.5 Australian Implementation guide co-developed with industry, that allows for both flexible export limits and emergency generation shedding rather than an alternative short-term technical solution that is likely to be stranded within 18 months of implementation. It is our understanding that this is technically possible today and may provide additional behind the meter and wholesale optimisation opportunities not afforded by remote disconnection/reconnection.
- We note that it may not be possible for all customers to have access to reliable communications e.g. rural/remote and suggest the regulations would need to provide a mechanism for such customers to be identified and provided exemption from these requirements. Alternatively, a stronger requirement could require these systems to be zero export limited.
- An incentive for those who can provide this capability for legacy systems e.g. via control of the inverter could be considered.

- We believe at least six months should be provided for industry to meet this obligation from the formal release of detailed requirements. The detailed requirements must include sufficient technical specification and implementation detail to provide clear guidance to industry.
- We would strongly recommend a staged implementation of this capability which would afford trialling of this capability to test both the technical implementation and the ability of the solar industry to deliver this capability as part of the end-end connection process. The entire DER eco-system will need to evolve to provide this capability, including solution providers, SAPN, salespeople and installers.
- Enhanced voltage management will provide a certain degree of this capability both for new and legacy systems and may afford a deferral of the start date for this requirement towards the end of Spring/Summer period and provide a significant buffer for implementation prior to Spring 2021.
- As mentioned in our covering letter, the Government may also gain value from establishing an incentive scheme, encouraging proponents to establish capabilities to increase load, or reduce solar PV generation, by overlaying additional technology to existing legacy equipment.

2. Consultation on the proposed export limit requirements for distributed solar generating systems in South Australia.

We strongly support this proposal as analysis undertaken by SA Power Networks[1] indicates that flexible export limits will deliver much better customer outcomes than fixed limits.

Export management is a critical capability for the efficient operation of a decentralised power system, and therefore implementation should be expedited to the extent possible, however, it is also enormously technically challenging and so a staged implementation is important to manage risk. The proposed remote/disconnect facility for solar generating plant will provide an appropriate interim backstop until this more advanced capability can be put into place, and on that basis, rushing the implementation of this more sophisticated capability is unnecessary and merely adds risk and cost.

We are actively working with industry to progress suitable technical standards in this area, however, we think it would be very difficult to fully achieve this capability before July 2022.

- We support this proposal as it's consistent with our AER approved Low Voltage Management Strategy[1], which demonstrated the best long-term outcomes for all customers by implementing this capability.
- Although we are highly supportive of market led solutions, the implementation of this capability would require a highly prescribed technical standard which should be stipulated in the regulations e.g. compliance with IEEE2030.5 Australian Implementation guide. The market would be free to find the most efficient solution for meeting that standard within a variety of different operating models and control architectures.
- SA Power Networks strongly encourages the SA Government to review the process by which the IEEE2030.5 standard is being implemented in California, the only jurisdiction in the world to our knowledge that has legislated the requirement for DER interoperability.
- SA Power Networks believe that this requirement should be broadened to include all Inverter Based Generating Plants, in particular batteries. It is essential for the operation of VPPs which export into the grid and any batteries which also have control of the solar PV generation. We note that it also benefits batteries in solar shifting mode as the export limit provides an opportunity for the batteries to optimise their storage patterns. For sites with multiple DER, it is likely that the standard will require one device to manage export limiting for the customer's site. These requirements will apply under SA Power Networks' connections rules following the implementation of "flexible exports".
- We note that gross output control is a viable alternative to (net) export limits. It eliminates the requirement and cost to have export metering on the customer's site although would not provide the customer an opportunity to optimise their consumption behind the meter. Ultimately, most customers will be better off under export limited options, however we would recommend the Government consider providing this option.
- As per Consultation Paper 1 – Remote disconnection, consideration will need to be given for customers who cannot access reliable communications due to their location.
- It is unclear from the Consultation Paper if this is intended but we think it would be unwise to implement a simplified, completely market driven interim dynamic export limit option which precedes SA Power Networks implementation of "Flexible Exports".
- It should be noted that the necessary capabilities to achieve these requirements will also meet the requirements of remote disconnection/reconnection.
- We understand there may be some current legal barriers that would prevent us from implementing this requirement for new and existing DER customers. SA Power Networks will need to seek approval from the AER to have both the Basic Connection Agreement and Deemed ongoing Supply Agreement amended to support the implementation of dynamic export limits.

[1] SA Power Networks AER Regulatory Proposal submission (Dec 2019). *LV Management Strategy Business Case*

- We believe July 2022 is the earliest practical time the industry would be able to achieve this functionality which is consistent with our planned implementation of "flexible exports". The prescribed technical standard will be developed, thoroughly tested, and refined as part of a trial undertaken over the course of 2021, and not available for formal publication until 2022. Importantly it also reflects a more manageable implementation timeframe given the new disconnection and reconnection requirements will be in place from an earlier date (preferably early 2021 as per our response above to Consultation Paper 1 - Remote disconnection).

3. Consultation on the proposed new low voltage ride-through requirements for smart inverters in South Australia.

We support the need for this change, but we understand there are concerns that the timeframe may not be achievable. It would be desirable to align this implementation with that for remote disconnection of solar PV so as to streamline the introduction of both requirements.

- The timelines to implement the obligations placed on SA Power Networks are extremely tight and although we have reviews underway to update our technical standards it is likely to be until at least the end of July 2020 before all are updated.
- We believe January 2021 may be a more realistic deadline for industry to achieve this functionality, provided the requirements, including test method and the implementation process, are clearly outlined and formalised before the end of July 2020. It is worth noting that SA Power Networks policy and standard industry practice is to provide a 6 month grace period for significant standards changes. This is also consistent with the process for changes to Australian Standards and OTR documents.
- An alternative to this approach could be the requiring of self-certification by manufacturers, aligned to an earlier timeframe, followed by independent certification when the full Australian Standard is released. An obligation could be placed on vendors to remediate any systems installed that are subsequently found to be non-compliant as a result of the later independent testing.
- As outlined in the summary we currently have limited capability and funding to police inverter compliance. We have limited visibility if equipment that is installed differs from the approval or is installed without going through the application process. These new requirements may add a further disincentive to correctly notify us of existing system upgrades or alterations. The OTR may have to take a more active role in compliance management in partnership with SAPN. It will be important to try and develop an agreed effective compliance regime between OTR and SAPN for this to have the full desired effect.
- To achieve reliable implementation, we believe it is critically important for this capability to be in-built into the default settings of the inverter, without requiring manual configuration by the installer
- SA Power Networks is not in a position to administer standards compliance listings and wish to confirm that the CEC would maintain and publish the list of <u>all</u> compliant inverters under this proposal, for the purposes of enabling customers and industry to easily identify compliant products, and to enable our implementation within the application process.
- We also note the implementation of this requirement may cause issues for batteries that have already been approved under the Home Battery Scheme.
- This requirement should only be applied to installations which have not yet been approved by SA Power Networks. This would reduce issues with customers who have already committed to purchase certain products.
- Finally, we have concerns the test conditions are not prescriptive enough to guarantee all inverters will perform as intended. There is a risk, as discovered in previous versions of AS4777, that the complete response of inverters is not captured by the test cases proposed by AEMO which may result in unintended or inconsistent behaviour. We will provide relevant feedback on this matter to AEMO.

4. Consultation on the proposed smart meter minimum technical standards in South Australia.

Noting that the consultation paper recognises a number of potential issues with this approach, we think considerable further consultation and technical assessment would be required, and so we do not favour mandating this or the September 2020 deadline. We strongly support this solution being considered for remote disconnect/reconnect (Consultation Paper 1 – Remote disconnection) where it provides the best value/lowest cost for the customer, but it should not be a mandated requirement to deploy this solution.

Why we don't support this solution as a default requirement:

- As acknowledged in the consultation paper, this solution would only be suitable for very simple sites with single phase supply and no controlled load.
- Application at more complex sites would require, as a minimum, a non-standard meter configuration with additional elements and contactors, however no product exists to our knowledge which would provide this control capability for 3 phase sites, requiring the utilisation of auxiliary contacts on the meter and additional contactor/s installed on the switchboard.
- By having the functionality in the meter, the applicability is constrained as it requires the switchboard to be in the same enclosure as the meter. Therefore, this standard would be cost prohibitive to implement in:
    - Most SA Housing Trust properties;
    - Units;
    - Many rural and remote properties; and
    - Any home where the switchboard / solar PV connection is remote from metering
- These alternate configurations will require new meter types, testing, complex wiring etc. which will increase costs to customers. It may also be challenging for meter manufacturers to provide new configurations given the low volumes presented by the SA market.
- To our knowledge, there are no standard metering arrangements that exist in Australia that would meet these requirements for these more complicated sites. This would impact costs, availability and spares (legacy issues). This will also lead to inconsistency in implementation.
- While the additional hardware cost of special metering arrangements may be relatively minor, in the order of $100, additional cost on consumers will be more significant due to the additional labour required to complete the more complex on-site wiring including additional CTs, contactors, power supply etc.
- In some instances, where additional space is required in the switchboard for these modifications, customers will need to pay upwards of $1000 for the upgrade. Old switchboards, including those containing asbestos, may further complicate what otherwise may have been a simple meter exchange.
- Given the inability to implement this requirement consistently across different customer types e.g. OPCL, 3 phase etc., there will be inconsistency in visibility, control capability and equity between customers.
- The proposed implementation must also consider the necessary requirements for small commercial/industrial customers who may have either whole current/CT metering, and also may have switchboards remote from the metering enclosures. For commercial solar installations, there may be multiple inverters and these may be connected across multiple switchboards, across different buildings on the site.
- Having a separate PV connection to the meter could require a change to the the solar installation process, for instance requiring the metering provider's electrician to complete the switchboard wiring, which may:
    - Further exacerbate the complexities, delays and customer dissatisfaction that has already been experienced through the implementation of Power of Choice (i.e. Retailer, Meter Coordinator, Meter Installer and Electrician to coordinate); and

    - May increases the implementation costs as the electricians will charge a premium for the administrative burden and inconvenience;

- The concurrent consultation on these smart meter minimum standards and the consultation on the remote disconnection/reconnection obligation has caused confusion within industry with this being seen as pre-empting a comprehensive design process which would determine the minimum requirements to meet the remote disconnection/reconnection obligation. It may be determined through the design process that smart meters are not a viable option to provide this capability, noting their reliance on public carrier communications networks in conjunction with a potential lack of appropriate "failsafe" response for the solar PV contactor. It may also be determined that the Metering Coordinators are not equipped to execute these emergency controls in a managed, coordinated and timely manner. A comprehensive design process will ensure every solution goes through a rigorous approval process before it can be deemed suitable for meeting the requirements.
- We understand that customers have an ability to opt out of communications when their meter is replaced, potentially diminishing the effectiveness of this requirement and increasing the likelihood of customers to exercise this right.
- To implement this requirement, new custom meter configurations, data streams and billing system changes will be required by MCs, MDPs, retailers and SAPN to ensure customers' in-house consumption is netted off against coincident PV generation. The cost recovery mechanisms for these changes may place additional costs on customers for the deployment of this solution.
- We understand that these requirements will likely cause issues at sites with home batteries configured to provide backup, a key motivator for customer adoption of home batteries. This may prevent the correct operation of backup/critical load supply functions, and cause issues with the necessary placement of the site net export CT on the network side of the meter.
- The confusion generated around whether the purpose of this proposal is to support options to enable the emergency control required under Consultation Paper 1 – Remote disconnection, poses the following risks:
    - inconsistency with the general approach of market led solutions which should permit industry to find the most efficient (compliant) means by which to meet the requirements;
    - duplication where alternate means deployed to meet other requirements in this proposal can achieve this functionality;
    - a disincentive for industry to create innovative solutions that can meet the requirements of (1), but deliver greater value for customers e.g. HEMS; and
    - leaving a legacy problem for industry, that might be quickly superseded by alternative low cost approaches (including those developed for dynamic export limits)
- If it eventuates that this is the only solution which is complaint and available by the deadline imposed by the Remote disconnection/reconnection process the Regulations should permit on-going flexibility to allow additional solutions to be deemed and made available as they are developed without requiring a repeal of a smart(er) metering mandate.

<u>Why this solution is unlikely to be available within the desired implementation timeframe:</u>

- We understand that in the 2 years since the introduction of metering contestability, Metering Coordinators have not been able to exercise the existing remote disconnect/reconnect capabilities of meters in South Australia due to concerns regarding frameworks, roles and responsibilities and safety. This will need to be overcome prior to making this capability accessible.
- While Metering Coordinators currently have the technical capability to operate individual meters, we understand that emergency disconnection orders, which require fleet level coordination of 10,000's individual meters in a short time frame, is not an existing capability. This will likely require end-to-end system design, implementation, testing etc. between SAPN, the Metering Coordinators and Metering hardware vendors before this capability could be relied upon.

- We should consider whether the capability of simply disconnecting net generating customers under emergency circumstances this spring, as undesirable as this is, would avoid the need for these immediate requirements, providing time for further consideration and consultation on how to most cost effectively achieve the desired outcomes.

5. **<u>Consultation on proposed tariffs to incentivise energy use in low demand periods in South Australia.</u>**

To the extent that retailers are able to meet the timeline, SA Power Networks supports this in principle as it aligns with our original proposal to make Time of Use tariffs standard for customers with interval meters from July 2020, which the AER deferred to 2021 in our final regulatory determination.

- We note that this requirement only requires passing this tariff through to customers on a standing offer and not market offers. Given the energy literacy of customers remaining on standing offers may be generally low, the effectiveness of this measure to incentive daytime load might be lower than expected as well as impacting on the overall pricing outcome for these customers.
- SA Power Networks would also like to incentivise retailers to deal with controlled load in a more sophisticated way. We will discuss this with the Department separately.