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Mr Warwick Anderson
General Manager
Australian Energy Regulator
GPO Box 520
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AER reference: 62729

By email: SAPN2020@aer.gov.au

15 January 2020

Dear Mr Anderson,

SA Power Networks - Determination 2020-25

AGL welcomes the opportunity to provide comments to the Australian Energy Regulator (AER) in relation to the AER Draft Determination (published in October 2019) (Draft Decision) and SA Power Network's (SAPN) revised access arrangement proposal (published in December 2019) for South Australia's electricity distribution network for the period from 1 July 2020 to 30 June 2025 (Revised Proposal).

AGL appreciates that there is an enormous amount of detail which SAPN had to prepare and for the AER to analyse and determine the efficient costs for the network business to operate in order to meet the NEO. The AER has highlighted the need for clarity, consistency and reasonableness in SAPN's expenditure plans.

After reviewing the Draft Decision and the Revised Proposal, AGL would make the following observations:

- The cost of capital is the key driver of lower revenue in 2020-25,
- Excluding the return on capital, the proposed revenue represents an increase in real terms from the current regulatory control period,
- Revised operating expenditure continue to increase each year in real terms,
- While the annual revenue requirement in the Revised Proposal is broadly in line with the Draft Decision, there are material differences in capital expenditure,
- The proposed price path and Tariff Structure Statement both appear reasonable, and
- The new reduced fee for cancelled requests is welcomed but there are large increases in many ancillary network service charges.

More detailed comments on aspects of the Revised Proposal are provided below.

Annual revenue requirement

The Draft Decision reduced SAPN's original revenue proposal by 7.4% or $310 million over 2020-25 to $3,905 million (nominal).

Responding to the AER Draft Decision, SAPN has reduced its total revenue requirement by 7% or $299 million over 2020-25 (nominal) to $3,916 million in its Revised Proposal. This is an increase of $11 million compared to the Draft Decision.

Table 1: Total Revenue (nominal $million), Original and Revised Proposals

	Original Proposal	Revised Proposal	Difference
Return on capital	1,277	1,046	-231
Regulatory depreciation	1,233	1,219	-14
Operating expenditure	1,671	1,560	-111
Revenue adjustments	40	84	+44
Net tax allowance	0	10	+10
Annual revenue (smoothed)	4,215	3,916	-299

Comparing the Revised Proposal with the Original Proposal, the main difference of $231 million is from return on capital which is due primarily to external factors, namely, the reduction in the cost of capital. Excluding this reduction, the total revenue requirement in the Revised Proposal is only $68 million or 1.6% lower over 2020-25 compared with the Original Proposal.

Importantly, if the reduction due to return on capital is excluded, the Draft Decision and Revised Proposal still represent an increase in 2020-25 revenue of about $90 million in real terms over the current 2015-20 regulatory control period (inferred from Figure 2 in the Draft Decision (Overview)).

Operating expenditure

The base-step-trend approach is used to set operating expenditure. While this simplifies assessment, this approach lacks granularity so the inclusion of a productivity factor of 0.5%, is a critical safeguard to ensure there is an improvement in efficiency. However, this approach tends to encourage only incremental improvement in cost efficiency, not step improvements in the baseline.

SAPN has revised operating expenditure down by $111 million to $1,560 million over 2020-25, $25 million (nominal) lower than the Draft Decision. However, even though costs have been revised downwards, operating costs over 2020-25 will continue to increase each year in real terms, exceeding the level of costs over 2015-20 by $147 million (Revised Proposal, Figure 6-2).

Revenue Adjustments and incentive schemes

Revenue adjustments were revised up by 110% from $40 million to $84 million (nominal) with changes particularly in EBSS and to a lesser extent, CESS.

The Revised Proposal included a turnaround in the EBSS carryover from a $30 million loss (forecast in the Original Proposal and Draft Decision) to a $4.6 million gain, resulting in an increase in EBSS of $35 million.

AGL understands the intent of incentive-based regulation but is not convinced the operation of these regulatory schemes provide any benefit to customers. These schemes encourage regulated businesses to propose higher operating and capital expenditures so that any under-spend provides future additional revenue. These incentive schemes may be producing unintended consequences, resulting in under-investment and a trade-off between short term and long-term interests. Since it is unclear if the actual performance is due to a business operating on a business-as-usual basis or more efficiently, these schemes should only be applied using baselines benchmarked against actual costs in a base year, not forecast costs. In additional, these costs should be targeted and not include costs such as GSL payments which are due to events outside the control of the distribution business.

Capital expenditure

Given the transformation in the energy market, such as the prevalence of distributed energy resources (DER) and digitisation, it is important that capital expenditure is not only prudent and efficient, but future proof.

Over 2020-25, capex in the Revised Proposal totalled $1,712 million which is at a comparable level with the 2015-20 capex of $1,702 million (June 2020$) (Revised Proposal, Table 5-2). While the 2015-20 capex may be a useful reference, it is important to ensure that these expenditures are optimised and have considered the changing market environment. As this revised capex is significantly higher than the Draft Decision, being 35% or $450 million more, AGL anticipate that the AER will assess the revised capex to avoid investment in assets which may be stranded as the energy market evolves.

AGL notes that during 2015-20, actual capex was less than the allowed capex in every year, resulting in an under-spend amounting to over $300 million (June 2020$) (SAPN – Revised Proposal - 9.1 – CESS Model). Accordingly, it is appropriate to consider if the proposed capex is prudent and efficient, and will therefore be fully spent or whether it will result in further revenue under the CESS.

Examining the categories of capex in Table 5-2, we note that net connection expenditure is forecast to be 54% higher in real terms over 2020-25 compared with 2015-20. While SAPN has noted that higher connections expenditure has been highlighted previously by a number of stakeholders, a forecast based on higher growth should be reviewed, given that actual demand has been below forecast in the current regulatory period.

An area which AGL expects some allocation of investment is in B2B processes to facilitate metering competition. Currently, the SAPN process to manage service orders for meter installation and replacement is email-based and is prone to errors arising from service orders and changes not properly communicated or received, leading to poor customer experience. This is not suitable in an increasingly digitalised market and will not be an acceptable operating process for the next five years. B2B processes are already in place with other distribution networks in the NEM.

DER Management

AGL commends SAPN's industry leadership in seeking to develop appropriate DER managements options. Nevertheless, we consider that further work is required by policymakers and the broader industry to develop a future-proofed solution before the AER approves substantial expenditure in this regard.

DSO transition program

We note that the AER has included the DSO transition program in the Draft Decision and has determined that SAPN has demonstrated the need and that it is the least-cost option. This represents an expenditure outlay of $30.3M as outlined in Table 5.4 in the Draft Decision.

SAPN's LV Management Business Case explained that this expenditure would provision, among other things:

- Implementation of an open interface (API) for data transfer, and systems for data storage and processing of time-series voltage data to attain visibility of voltage variations in the LV network ($11.99m);
- Development of a template-based model of LV network topology and hosting capacity limits, and new processes to centrally manage LV switching ($7.76m); and
- Establishing a system for LV network constraint calculation and publication of dynamic export limits to DER operators and aggregators and VPP operators via an open API ($5.46m**)**.

AGL supports the industry's transition towards a more mature distribution market, entailing a distribution market operator and supporting communications infrastructure to enable co-optimisation of bidding from distributed energy resources to support both network and wholesale markets. However, until such time as policymakers and industry settle upon an appropriate distribution market design, premature investments in distribution market operating systems risk creating stranded assets both for SAPN and for hardware vendors and virtual power plant (VPP) operators seeking to integrate into SAPN systems that may not be fit-for-purpose in the future. We are concerned that the proposed cost components outlined above (totalling at least $25.21M) as well as the costs to industry to integrate with these systems may become stranded should an alternative model be adopted.

AGL has been closely engaged in recent industry consultations concerning distribution market design, including through the Energy Security Board's work program on the Post 2025 Market Design for the NEM and the Open Energy Networks consultations. We would welcome the development of a market model that has been tested through market trials and is widely supported by the industry as the most efficient and effective model to allow customers to engage and share in DER value.

Given the risk associated with SAPN's proposed DSO transition program expenditure, we would recommend against the approval of this capital expenditure at this point in time. In our view, SAPN should instead focus on operating expenditure and spend on facilitating the delivery of competitive market solutions until such time as there is agreement amongst policymakers and industry on the appropriate distribution market design.

QoS and LV monitoring

Given the growing customer and policy expectation that DER will play an increasing role in supporting Australia's energy markets (including through aggregated programs such as virtual power plants, it is important that SAPN effectively manages quality of supply issues in the short term whilst also progressing more comprehensive solutions that enable the effective integration of DER in the future. SAPN has revised down the cost to augment the quality of supply by 6% to $41.4 million.

SAPN has also revised the cost of the LV transformer monitoring program from $18 million to $5 million. This program is to establish permanent load monitoring at about 2,000 LV transformers for load forecasting purposes. SAPN expects the use of this transformer monitoring data and customer load profiles from smart meters will be more efficient and accurate.

AGL supports the expenditure on quality of supply and LV transformer monitoring program as it is important to continue to invest, prudently, in DER integration. The revisions compared with Draft Decision are relatively minimal in the context of total capital expenditure, and we also note that SAPN has included a negative step change (i.e. savings) in operating expenditure due to the LV monitoring program.

Price path

In the Revised Proposal, SAPN has proposed a price path over 2020-25 with a lesser P_0 reduction but a higher X-factor (i.e. a smaller initial reduction followed by lower increases in subsequent years) than the Draft Decision. AGL supports this revised price path which will reduce the overall volatility of network price changes.

Tariff Structure Statement

We note that in the Draft Decision, the AER has substantially accepted the Tariff Structure Statement in the Original Proposal. AGL supports the significant changes in SAPN network tariffs which recognises the fundamental shift in the demand load profile due to the penetration of rooftop solar in South Australia as well as the move to more cost reflective network tariff structures.

The changes include new TOU tariffs with a 'solar sponge' rate, prosumer demand tariffs, locational large business demand tariffs, assignment to the new TOU tariffs from 1 July 2020, and increasing the proportion of fixed supply charges to volumetric charges. We expect SAPN to engage with retailers to resolve any operational issues with metering and billing arising from the introduction of these new tariffs.

Ancillary Network Services

It is appropriate that all ancillary network service charges reflect efficient costs. We acknowledge the important role of the AER in reviewing and benchmarking the underlying costs to provide these services as service providers and customers have little or no power to negotiate with SAPN on these fees. Benchmarking is also important because many services are provided by external contractors and the costs are passed through to retailers and customers.

We welcome the introduction of a low fee for all cancelled special meter read, disconnection and reconnection requests (NDS388) to replace the same fee charged for both completed and cancelled service orders, While we understand that this reflects the arrangement under an external services contract which SAPN has entered into, we maintain that, in line with many other distribution networks, no fee should be charged if the service request is cancelled more than 2 business days of the scheduled service.

There are significant increases in many ancillary fees. Increases of 63%-119% in multi-phase upgrades (BCS109, BCS110) will impact retailers and customers who install smart meters. We support the AER's recommendation that SAPN consider a transition plan for fees with significant price increases.

There are differentiated ancillary fees where retailers are not in position to identify the relevant fee to quote. These include fees for services such as temporary disconnection and reconnection (NDS302 & NDS330 and NDS430 & NDS431) where there are large differences between a truck attendance and a single person crew. These fees are currently the source of many customer complaints and there should be consideration on how these fees could be simplified or consolidated.

We are also concerned about the introduction of a new fee for third party disconnection and reconnection where there is a shared isolation fuse (NDS457). This service is necessary as a result of SAPN's decision in the past to supply multiple customers to a single service fuse. As meters are replaced with smart meters, separate isolation fuses are also installed so that the additional work will also benefit third parties and to improve SAPN's assets. Therefore, we do not agree with the charge for multi-occupancy isolation.

If you have any questions in relation to this submission, please contact Meng Goh, Senior Manager Regulatory Strategy, on [redacted] or [redacted].

Yours sincerely,

[redacted]

Con Hristodoulidis
A/GM Energy Market Regulation