Consumer
Challenge
Panel

CCP14

Response to the SA Power Networks 2020-25 Draft Plan and Early Engagement

Submitted to the AER
8 October 2018

CCP14 has reviewed the SA Power Networks 2020-25 Draft Plan. We can confirm that we have made relevant checks to ensure that to the best of our knowledge, the document does not contain any confidential material or material that is commercial in confidence. This document can be published on the AER website.

1. Overall assessment of SAPN's Draft Plan

The letter from Rob Stobbe ("CEO Letter"), the SA Power Networks (SAPN) CEO at the front of the Draft Plan is headlined:

> *"Delivering better outcomes at a lower price".*

It goes on to say that:

> *"…our customers want us to"*

- *do our part to **keep a lid on prices** (emphasis added), noting we represent approximately 26% of a typical residential customer's electricity bill;*
- *maintain electricity supply reliability across the State; and*
- *continue a managed transition to the 'network of the future'."*

Whilst SAPN's obligation to maintain a safe and reliable distribution network is unquestioned, we consider that the Draft Plan is not completely aligned with the customers' position we observed in SAPN's various engagement activities over 2018. For example, in the Opex deep-dive of 3rd May 2018, SAPN represented the clear messages from consumers as [1]:

- *SAPN needs to be as efficient as possible, and **continue to look for efficiencies***
- *Strive to deliver network price reductions through **efficiency and innovation***
- *'Do the same for less'.*

We believe SAPN's Draft Plan is largely as a 'business as usual' plan. It does not aggressively *continue to look for efficiencies* nor deliver all achievable price reductions *through efficiency and innovation*. The majority of the objective of "*delivering better outcomes at a lower price*" is being achieved by factors other than specific actions by SAPN to deliver the lowest costs and most efficient network service possible. The relatively small headline fall in prices in year 1 is substantially due to SAPN applying the lower rate of return set out in the recently published AER Draft Rate of Return Guideline – a guideline that SAPN is strongly opposed to[2]. Applying the rate of return that SAPN seems to be arguing for would mean a price path of CPI increases over the 2020-25 period with no fall in year 1.

Our interpretation of Chapter 2 of the Draft Plan "Delivering Services Efficiently" is that "as SAPN ranks high in productivity comparisons, it has less ability than lower ranking networks to further improve its productivity". This view is confirmed by SAPN discussing consumers seeking to have a productivity factor in opex (p.56):

> *"We do not support this approach as further productivity growth must represent industry-wide efficiency gains. As a leader in efficiency, it will be more difficult for SA Power Networks to*

[1] Refer slide 20 of the SAPN Deep Dive presentation, 3 May 2018

[2] See the joint submission by SAPN, Citipower, Powercor, AGIN and United Energy to the AER 25th September 2018
https://www.aer.gov.au/system/files/Joint%20Energy%20Businesses%20Final%20Rate%20of%20Return%20Submission_Redacted.pdf

achieve additional, across-the-board productivity gains than less efficient distribution businesses, and we will be penalised if we cannot meet those gains."

The AER productivity data for the 2006-2016 period indicates that SAPN's experience mirrors many other DNSPs:

- Overall multi-factor productivity fell 2006-2014 but has improved in recent years, but it is still ~15-20% less efficient than it was in 2006
- Capex productivity has consistently fallen over the period 2006-16
- Opex productivity fell from 2006 to 2015 but improved in 2015-16 and this drove the improvement in overall productivity, and
- These relative movements across all DNSPs have enabled SAPN to continue to be in the top 2-3 of DNSP productivity.

It is this improvement in recent years that has led the AER to initiate a review of opex productivity and their current zero productivity assumption. These improvements suggest that the efficiency frontier is moving out and some level of productivity should be incorporated into the AER's assessment of the base opex for an efficient an prudent operator. Some networks have decided not to wait for the AER review results and are responding to consumer feedback offering opex productivity improvements for their next reset period where 100% of the benefit goes to consumers[3]. These include Tasnetworks Distribution which had higher opex productivity than SAPN over 2013-2016.

SAPN's approach is to reject consumer feedback and adopt the AER zero assumption. This means any productivity gains are part of the EBSS where SAPN keeps 30% of the benefit. SAPN see any change in its productivity assumptions are part of the AER review. CCP 14's view is that consumers should get 100% of the benefits of trend productivity changes leaving networks to improve on the AER allowance through the EBSS.

Energy prices are a critical component of consumer and business wellbeing. With all networks emphasising the importance of "consumer at the centre" of their activities, we encourage SAPN to explore every possible opportunity to seek efficiencies, cost reductions and innovations regardless of its perceived relative position of performance with other utilities.

Apart from the zero opex productivity assumption, the implication of this largely "BAU approach" is seen in other ways:

- the lack of a strong imperative or passion for lowest possible prices for customers in the Draft Plan. There is little sense of a culture of 'stretch targets'. We acknowledge a number of initiatives to do things differently, such as in areas of asset management or bushfire mitigation modelling, however those initiatives do not seem to be resulting in lower prices for consumers. Our assessment is that these initiatives tend to improve the technical performance of the network at similar or higher cost to all electricity customers. Addressing consumers' core concerns on affordability does not seem to be held clearly as the prime objective of the plan.
- increased capital investment in areas such as reliability, non-system support and asset replacement that is not unequivocally backed up by data or customer imperatives. We are strongly of the opinion that there are unrealised opportunities to reduce prices to consumers

[3] Essesntial, TasNetworks Distribution, Energex and Ergon

even further; including productivity improvements, questioning the justification and efficiency of a number of capital investments, and delivering the maximum benefit of the significant IT investment programme.

We acknowledge the rapidly changing network environment in South Australia, driven largely by government policies influencing relatively rapid changes in customer energy needs, including distributed energy resources (DER). We respect the fact that investment is needed to better understand the network with the view of efficiently and productively integrating these new energy sources. We continue to encourage SAPN to take a powerful customer-centric view of this work to maximise the appropriateness of their approach and to increase the likelihood of a successful investment. We do not get a strong impression that SAPN has fully embraced the views of those customers both with and without DER in planning a course through this challenging environment.

In summary, we do not agree that the Draft Plan :

> *"…strikes the appropriate balance between customer service, network safety and price affordability. … in the long-term interests of our customers."*[4]

Our assessment to date is that the draft proposal reflects an intent by SAPN to provide a high quality, versatile electricity distribution network for electricity consumers. This in itself is commendable. However, in light of the broader view of high, in some cases debilitating, energy prices, such an approach is inconsistent with the expectation of the more empowered, more efficient and autonomous energy communities that are emerging. A clearly demonstrated imperative for lower cost, more productive utilities that value every customer dollar is critical. Such a passion is not clearly evident in the SAPN draft proposal.

We present these comments in a constructive light, recognising that SAPN has undertaken a very enthusiastic and extensive engagement program, which to date reflects the spirit of generating informed community comment to allow the 'hard conversations' before the regulatory proposal is submitted. We note SAPN's advice that this part of it's engagement program is intended to focus on consultation to allow SAPN to refine its thinking prior to lodging its draft revenue proposal in January 2019, rather than having ongoing engagement.

Our comments in this document highlight the opportunities for these 'hard conversations' in further substantive engagement prior to the finalisation of the 2020-25 regulatory submission and we encourage SAPN to take up that opportunity and to develop a submission that more fully reflects the true needs of the wider community, leading to general support of the SAPN proposal.

Mark Grenning (Chair), Louise Benjamin & Mike Swanston

CCP14

[4] CEO Letter

2. The purpose of this response to the SAPN Draft Plan

SAPN commenced their engagement for the 2020-25 regulatory reset over 12 months ago, setting a commendable standard in the latest round of resets. We have been welcomed to the significant number of workshops, information sessions and reference group meetings that have led to the publishing of the Draft Plan.

CCP14 commends SAPN for this early engagement approach, and we are very supportive of the way SAPN has made this Draft Plan available to energy consumers and other stakeholders in the state.

The SAPN 2020-2025 Draft Plan is a significant milestone in the engagement process.

Key to the success of the engagement is that the Draft Plan is seen not as a summary of the eventual regulatory proposal, but as a lightning rod for conversation, comment and feedback. Critical is the way SAPN receive and consider the feedback, and listen to the sentiment, questions and emotion presented in the feedback to the Draft Plan. It is now time for the 'hard conversations' to assist SAPN to understand the issues as seen by the energy consumer and ensure that their regulatory proposal demonstrates 'listening and responding' to the issues raised.

Over the next couple of months, CCP14 will keenly watch the way SAPN considers the feedback from the range of stakeholders, interacts with its Customer Consultative Panel (SAPN CCP) and Reference Groups and takes this excellent opportunity to incorporate the advice by modifying, adapting and improving their proposal to best reflect the needs, thinking and suggestions from stakeholders.

The role of the SAPN CCP and CCP14 has expanded recently to provide much more focus to the early engagement stage prior to the network's formal submission of its proposal to the AER. We view this as an important step in the maturing landscape of community engagement related to a regulatory reset. It provides a great opportunity where key issues can be aired and considered by a network business with the view of presenting a regulatory proposal that is 'capable of being accepted'.

We believe the audience of this CCP14 response is:

a) the Australian Energy Regulator (AER), to assist in the identification of key issues and the engagement with SAPN in the lead-up to, and after, the regulatory proposal is submitted;

b) SAPN, to identify areas of community concern and opportunities to improve their proposal, assisting in its acceptance by customers and community groups; and

c) other community groups and stakeholders in the SAPN reset engagement process, to assist in clarifying matters against which the level of engagement and 'listening' for proposal can be measured.

3. Overview of SAPN's 2020-25 Draft Plan

The Draft Plan is quite extensive and contains a lot of commentary. From the Draft Plan and the lead-up information sessions ('deep dives'), we have distilled the following key points as being of most interest to consumers:

1. AEMO demand forecast net summer demand will decrease at an annual average rate of 1% over 2020-25 given the impact of expanded solar and batteries together with slower economic growth and the further impact of energy efficiency.
2. Network growth is small as overall customer demand is forecast to decline with only marginal increases in customer numbers and power line length for localised demand growth.

3. A price outcome in the 2020-25 plan of a reduction of $37 in the average annual residential bill, and $148 in the average SME business bill. This is achieved by a CPI-3.9% step in 2020/21, followed by CPI price rises in subsequent years.
4. Operating expenditure of $1.468b - a 10% increase in real terms over the forecast opex in the current 2015-20 period. This opex number is a small ($49m/3.2%) fall from the number presented at the start of the consumer engagement in 2018. Around half of this was a fall in proposed changes to ESCoSA's GSL payments scheme.
5. SAPN does not support the inclusion of productivity growth sought by customers and stakeholders, highlighting the cost of increased solar connection enquiries, higher expectations of vegetation management, more demanding safety standards and the impact of climate change on major storm events.
6. $34.7m in opex step change increases, largely around IT services and data, moderated by a $22m reduction related to a proposed change by ESCoSA to cap some GSL payments.
7. In the current 2015-20 period, an expected 'across the board' underspend in capital expenditure of approximately 18% ($370m) across most categories, including demand driven (-28%), reliability (-13%), asset replacement (19%) and non-network (-17%). SAPN advise that this under-expenditure is largely due to storm activity diverting resources to emergency works, and uncertainty in funding due to AER challenges.

   The exceptions to the general under-budget performance are a forecast increase in capital expenditure on safety (+$28m, 165%), strategic (+22%) and IT (+3%).

   We note that against this overall under-expenditure, SAPN has not advised of any significant reduction in network safety, reliability or service.
8. When compared to the current period's capital expenditure, SAPN are planning an increase in capital expenditure by $146m (9%) in 2020-25, to a total of $1.851b.

   Reductions in expenditure in demand driven augmentation of $87m (-34%), customer contributions (-22%) and IT (-15%) are more than made up by planned increases in expenditure for asset replacement ($112M, +18%), reliability (+103%), safety (+84%), strategic (+10%), fleet (+17%) and property (+55%).

   This capex number is relatively small ($90m/4.7%) reduction from the number presented at the start of the consumer engagement in 2018. It is acknowledged that the initial reduction in capex as a response to customer feedback was $122M. This amount has been tempered by a proposed increase in customer connections expenditure following revised economic forecasts.
9. Strong growth in distributed generation and energy storage will continue, encouraged by government policy and subsidies. SAPN will continue to be at the leading edge of DER integration and have included $37m to 'transition to a new energy future' ($20m less after deep dives) in their strategic capital expenditure plans to better understand the 'hosting capacity' of their network.
10. SAPN plan to invest $28m in non-network opportunities and $4m in trialling new technologies (R&D)
11. Overall impact of the capex expenditure is the regulated asset base increasing by 7% in real terms over the 2020-25 period from $4,339m at the end of the current period to $4,641m at the end of the next period on 30th June 2025.

12. SAPN has proposed a prosumer VPP tariff, but not on a mandatory basis. It has also proposed a default residential ToU tariff with off peak periods designed to shift load into the middle of the day when there is maximum excess solar energy. Changes to current ACS structures and costs are minimal, with a focus on the costs and engagement regarding public lighting.

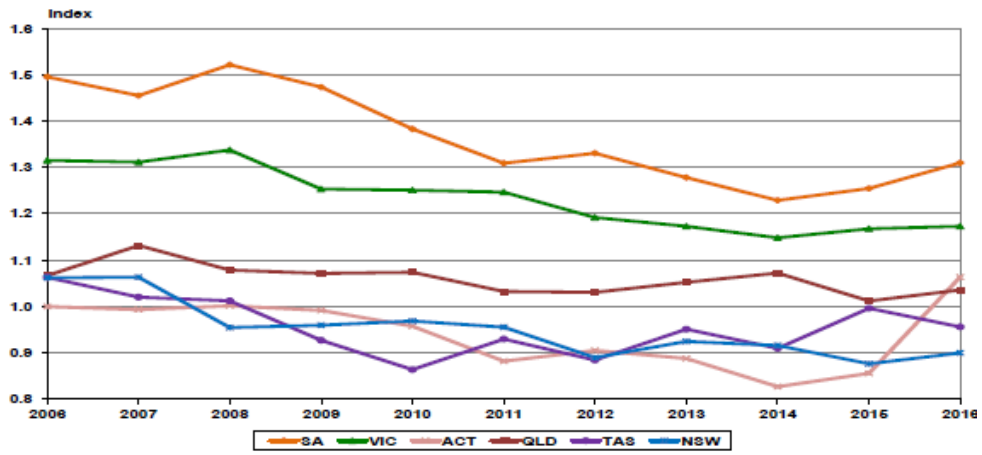
13. SAPN has proposed a Riverland DM strategy. There is little other discussion of DM initiatives despite SAPN being one of the few DNSPs to spend its DMIA.

4. How efficient is SAPN?

The Draft Plan highlights SAPN's total factor productivity performance as shown in the 2017 AER Benchmarking report[5], though the Draft Plan does not indicate the rankings apply to 2015-16. It shows that South Australia (i.e. SAPN) is the most efficient State for DNSPs and SAPN is the second most efficient individual DNSP, behind CitiPower, which covers central Melbourne.

What the Draft Plan does not show is trend productivity, which is a much more useful measure. The figure below from the AER 2017 report shows that SAPN's overall productivity fell significantly over the period 2006-2014, with some improvement since then, as has been the case for most DNSPs. So while SAPN may be "relatively efficient" compared with other DNSPs in 2015-16, even with the recent improvement, SAPN's productivity in 2015-16 was still 15-20% below that in 2006-8. This trend was similar for most other DNSPs and it is this generally poor productivity trend overall that has kept SAPN in the top quartile of efficiency - not because SAPN has increased its productivity. We expect that productivity across many DNSPs, especially in NSW and Queensland, has continued to improve since 2016, but it remains to be seen how this will impact SAPN's relative position. The AER data for 2016-17 will be published in November.

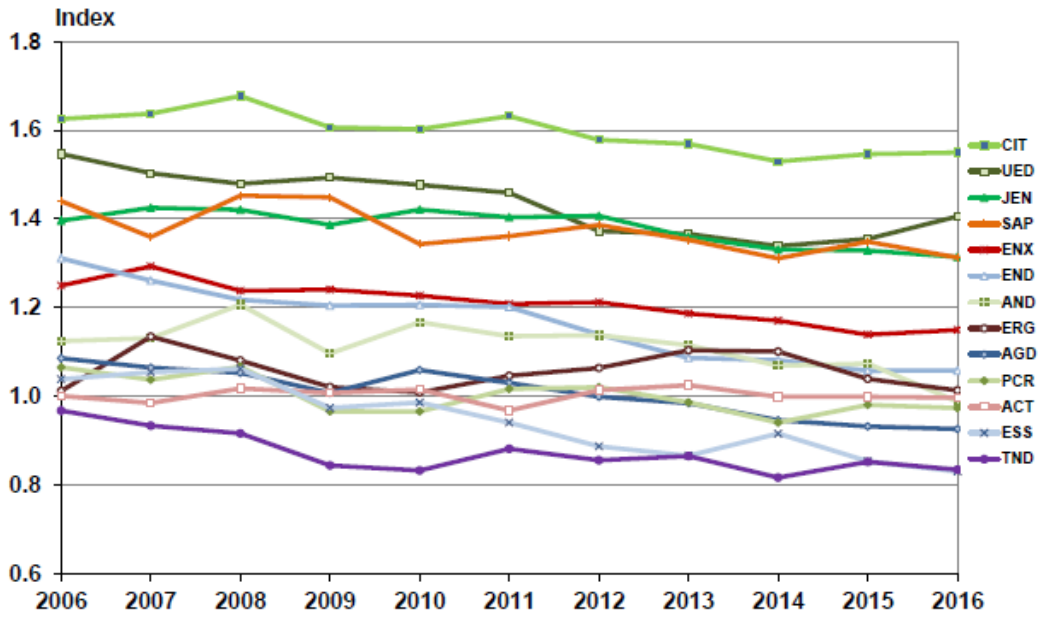
Figure 4 Multilateral total factor productivity, by jurisdiction, 2006–16



SAPN's capex productivity, like that of most DNSPs, has gradually declined over the 10 years of AER data.

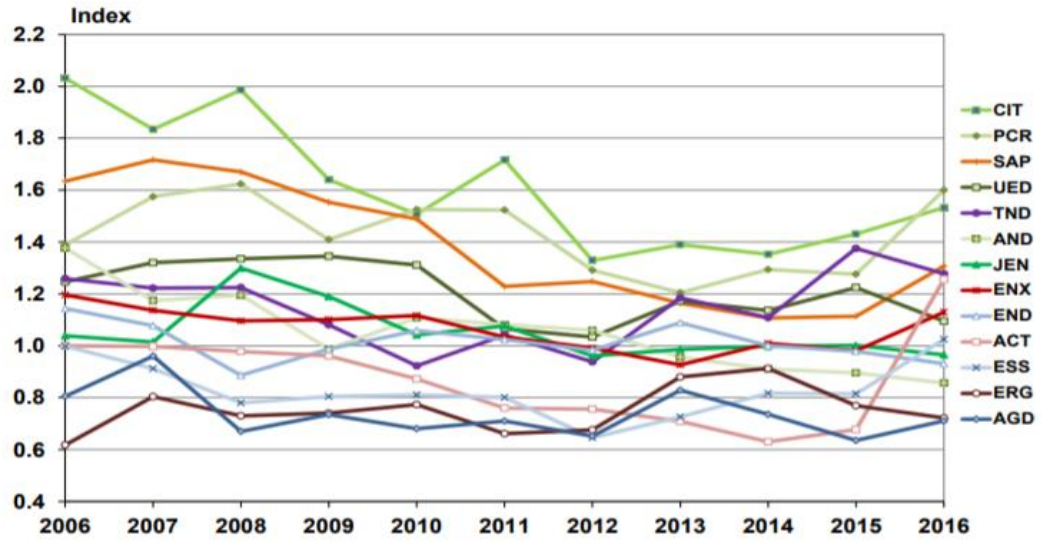
[5] See AER "Annual Benchmarking Report Electricity Distribution Network Service Providers" November 2017 p. 8 https://www.aer.gov.au/system/files/AER%202017%20distribution%20network%20service%20provider%20benchmarking%20report.pdf

Figure 16 Capital multilateral partial factor productivity (MPFP), 2006–16



SAPN's trend opex productivity has fallen over the last decade as shown in the following Figure[6]. In 2015/16 the latest year where data is available, it was ~24% lower than a decade earlier. There has been a stabilising and then improving trend in the last couple of years of the AER data and, from the comments in the Draft Plan, SAPN expects this trend to continue in the 2016-17 data to be published in November. The Draft Plan shows that SAPN ranked third of the 13 DNSPs, but all that indicates is that the opex productivity of the rest has fallen enough to ensure SAPN, despite its significant fall, stays in the top three.

Figure 17 Opex multilateral partial factor productivity (MPFP), 2006–16



[6] See AER op cit p. 37

The AER economic regulatory framework is designed to replicate what occurs in a workably competitive market – to assess the level of costs that would be incurred by an efficient and prudent operator. The workably competitive market that many consumers, particularly those in business, operate in outside the protection of a regulated return is one where failure to make continual productivity improvements is a fast way to exiting the market.

SAPN's response to this view is[7]:

> *"We agree that 'efficiency' is a relative term and we quote it as the AER uses it in its Benchmarking reports. Overall efficiency since 2006 as measured by the AER's preferred model is declining. This is largely due to outputs (Max demand (MW), energy delivered (MWh), circuit kms, customer numbers, reliability) being static or declining due to factors outside our control (economic conditions, customer take-up of PV (often with Government incentives), more efficient appliances being adopted, high overall electricity prices) and inputs (capital and opex) increasing. Our inputs (capital stock and opex) do not automatically reduce when outputs do as:*
>
> - *We can't generally remove capital stock (which often has useful life of >50 years) incrementally because overall max demand and throughput decline. For example, it's not possible (or practical) to remove 20% of a substation transformer because customer demand drops 20%. Declines in demand / throughput may be temporary, and removal of capital stock would only occur if there were a clear case of asset redundancy. Where demand / throughput does lower, and assets are due for replacement, we would of course consider replacing some plant with smaller plant or other non-network alternatives; and*
> - *Opex has increased for many reasons. For SAPN in the time frame considered by the AER's MTFP analysis, we have incurred vegetation management cost increases from the breaking of the 'millennium drought', labour/materials price increases, insurance costs increases, implementing changes to meet higher safety standards, higher cost GSL schemes, increased regulatory reporting (including for example, significantly expanded Distribution Annual Planning Reports and new system limitations reports, annual regulatory information notice reporting and auditing requirements, rule changes (e.g. metering contestability and ring-fencing), more non-network solutions, more information for customers, increased IT (cloud) etc. etc. etc.*
>
> *The AER's model does not illustrate these and other obligations and complexities that have been imposed on DNSPs*."

We agree with the comments on the difficulty of removing capital stock. This is why consumers have so much focus on proposed capex expenditure to ensure that it is essential and does not get into the RAB where it cannot, unless there are voluntary write-downs, get out until it is fully depreciated. Poor capital decisions in the past that have led to the relatively low levels of asset utilisation across DNSPs. SAPN highlights that its current asset utilisation rate is above the DNSP average, but again this is a relative position which has deteriorated significantly over the last 11 years.

[7] SAPN Correspondence to CCP14 6th September 2018, in response to specific questions raised by CCP14

	2006	2017
SAPN	71%	57%
Average of all DNSPs	57%	47%

Figure 1 - Network Asset Utilisation (source: AER)

We also agree with the comments around SAPN facing a variety of costs pressures. But this is no different to any other company. The difference here in a regulated environment is the apparent expectation from SAPN that it should have a cost pass through rather than absorb those costs through productivity improvements.

5. Key issues in the SAPN Draft Plan and engagement to date

5.1 Cost savings to customers are largely due to changes in regulatory and economic factors, and a real and aggressive reduction in cost to customers directly as a result of initiatives by SAPN is not evident in the plan.

Revenue

The Draft Plan 2020-2025 revenue of ($2020) $3,893m is only 1% below the allowed 2015-20 revenue of $3,931m ($2020). The impact of different factors on total revenue are:

Preliminary build-up presented for consumer engagement in 2018	+2%
WACC impact	-4.6%
Changes following consumer engagement	-1.3% (-1.22% from the opex reduction and -0.06% from the capex reduction)

Figure 2 - Revenue Requirement analysis (Source: SAPN, CCP14 analysis)

Without the benefit of the recent Draft AER Rate of Return Guideline and lower interest rates, the total revenue in the Draft Plan would have been 3.8% higher than the current period allowance.

$2020m	**2015-20 Allowance**	**2020-2025 Draft Plan**	
		2018 Draft Guideline and forecast interest rates	2013 Draft Guideline and interest rates in current 2015-20 period
Total revenue	3,931	3,893	4,079
% change from 2015-20 allowance		-1%	+3.8%

Figure 3 - Revenue Requirement analysis (Source: SAPN, CCP14 analysis)

We recommend that SAPN make it clear to customers as to the underlying causes of the proposed price reductions, perhaps in the form of a 'waterfall' chart.

Capital

SAPN notes in the Draft Plan a saving of around $280m in future network charges, largely as calculated through the Capital Efficiency Saving Scheme (CESS) model, as a result of a $370m reduction in capital spending in the 2015-20 period [8].

The data from the capex workshop shows that over one-third of this reduction is due to a steep decline in expenditure in demand-driven augmentation and connection costs, similar to that seen in other states and jurisdictions as a result of external factors such as falling demand growth, improved appliance efficiency and a response by customers to higher energy prices. Some, but only a small proportion, of these savings can be attributed to specific actions by SAPN to drive down costs.

We cannot see evidence where the underspend of allowed funds in the current period for items such as asset replacement, fleet or property is as a result of innovation or intentional actions by SAPN to enhance the efficient commitment of the funds. We observe that, in part, the explanation for the underspend is as a result of regulatory uncertainty and the reallocation of resources to storm response.

Our point is that some of the benefit of the $380m in underinvestment in the current period is due to external factors, and not as a result of powerful initiatives undertaken by SAPN. We have concerns that a large part of the $137m increase in proposed spending in 2020-25 is likely to be a 'claw-back' of work and projects not undertaken in the 2015-20 period.

We recognise the deferral of capital investment in network augmentation as a result of demand reduction is common across most network businesses, and is not unique to SAPN. As a principle, we look forward to the AER closely scrutinising the reasons for the underspend to see that they properly qualify for CESS benefit, in cases where the saving is due to external factors rather than a specific and intentional approach of improving efficiency by the utility.

We note the following advice from SAPN in various emails:

> *As explained in our Draft Plan the primary reasons for our underspend are:*
>
> - *actively deferring some work programs, in particular asset replacement work;*
> - *significant storm events in 2016/17 necessitated re-allocation of resources from capex to opex for emergency response;*
> - *the development of additional methods to defer the high cost of replacement;*
> - *actual customer demand being lower than forecast, which allowed prudent deferral of a number of augmentation (substation and sub-transmission) projects; and*
> - *lower than forecast costs for the Kangaroo Island cable project.*

5.2 SAPN's changes as a result of consumer engagement to date have been modest and had little impact on the total proposed revenue or prices.

We note the changes SAPN has made between the information presented at the 'deep dive' workshops and the Draft Plan, as shown in the Figure below. Nearly 50% of the reduction in opex was as a result of a change in ESCoSA GSL payments with the other 505 due to SAPN action to reduce expenditure. We acknowledge SAPNs work with ESCoSA to address the cost of GSLs, with a mixed

[8] Draft Plan, page 4

response. The reduced cost of GSLs will support lower prices for all electricity customers, however a lower GSL will provide a weaker incentive for SAPN to meet performance targets. Overall, we see this as a 'neutral' outcome for the community.

$2020m	Preliminary Plan Nov 2017	Draft Plan Aug 2018	Reduction $m/%	Comments
Opex	$1,517m	$1,468m	$49m/3.2%	• Reduction in step changes from $56m to $13m driven by a $22m reduction in ESCoSA mandated GSL payments • Reduction in trend from $55m to $50m
Capex	$1,940m	$1,850m	$90m/4.7%	• Reduce demand-driven investment by $87m • Repex $726m - reduced by $49m after deep dives (pg. 5) • Reliability $37m + $36m is $20m less after deep dives • Safety = Bushfire $19m + protection upgrades $24m + substation infrastructure $40m. (reduced $24m after deep dives) Customer connections increased by $32m

Figure 4 - Changes to key line items as a result of consumer engagement (Source: SAPN, CCP14 analysis)

5.3 In the current regulatory period, SAPN appear to be able to maintain a safe and reliable network despite underspending the regulatory allowance. We expect the aggregate expenditure in the 2020-25 period to be less than that of 2015-20, when considering overall network performance and key customer risk indicators appear to be stable and under control, overall energy demand is falling, customers become more autonomous

The Figure summarises the top-line expenditure for the current regulatory period and the Draft Plan.

$2020m	**2015-20**		**2020-25**
	Allowance	Forecast	Draft Plan
Opex	1,376	1,331	1,468
Capex	2,080	1,713	1,850

Figure 5 - Summary of current period forecast and proposed funding (Source: SAPN)

While both capex and opex have been underspent (capex by 18%) in the current period, SAPN still has exceeded its reliability service standards [9].

[9] Draft Plan p.13

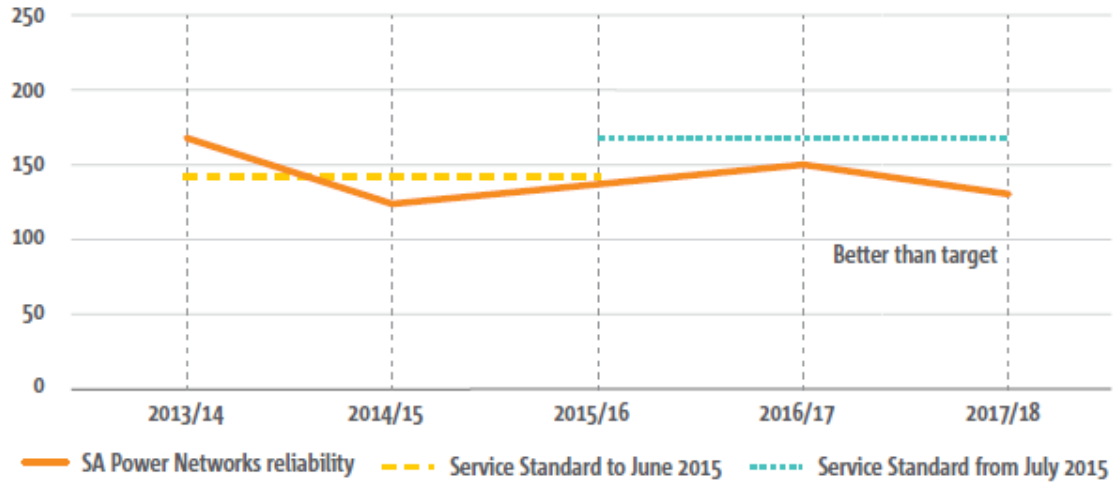


Figure 2.3: Electricity network system reliability[2] (excluding major event days) — average minutes of outages per customer

In the workshops and draft proposal, SAPN highlights the requirement for increased expenditure in areas such as safety, environment, strategic capital, property and asset replacement. In addition, we note the real increase proposed in operating costs.

Throughout the workshops, the application of the increased funds was mentioned, but the reasons why the projects, if important, could not be undertaken through a prioritisation of existing funds was not discussed. Similarly, the impact of these additional projects in terms of justified changes to key performance measures was not presented.

However, we have seen little evidence to suggest that the lower level of expenditure and investment, such as an 18% underspend in capital allowance this period, has been to the detriment of network safety, increased risk to the public, degraded network performance due to controllable factors, a degradation of customer service levels or bushfire risk. Particularly given the AEMO demand forecasts.

Therefore, we question why the opex and capex levels in the current period - to which the ongoing productivity improvements to meet the customers' call for "do more with less" are then applied - are not seen as adequate for SAPN to deliver a service commensurate with customer expectations and regulatory obligations. The greater demands in utilities through issues such as ring fencing, insurance and DER are recognised, however the 'with less' part of the objective is not evident.

5.4 We have not seen the evidence that some capital expenditure items are well supported by data or the sentiment of the community through informed and balanced advice, in particular those that are planned to increase in the next period.

SAPN notes that the additional expenditure above and beyond that of the current period spend is a result of targeted programs supported by feedback from customers from early stages of the engagement.

We do not suggest that investment in safety, reliability, bushfire mitigation or customer service is not justified. What is unclear is why this has to be *additional funds*, and cannot be seen as an extension of prioritisation of existing levels of investment. From our observation of early engagement, CCP14 is of the impression that it was not clearly understood by customers that when SAPN sought support for these programmes that SAPN would require additional funds.

For example, SAPN propose to invest an additional $36m of capital above the current $37m to maintain supply reliability levels and in fact improve network performance in some areas. The justification for the additional expenditure beyond the current supply reliability programmes, when network reliability is generally meeting ESCoSA targets, is unclear.

The planned investment of $19m in bushfire mitigation programmes is consistent with current trends. What is not clear, however, is the justification of additional funds of $24m in protection equipment replacement and another $40m in substation infrastructure and this needs to be considered closely.

Overall, as we noted above, we do not accept the SAPN foundation argument that their position on AER benchmarking means "…it will be more difficult…to achieve additional, across-the-board productivity gains…".

5.5 Whilst acknowledging the somewhat unique circumstances of DER growth in SA, the direct impact of SAPN's investment plans from the point of view of the energy customer remain largely unexplained.

We acknowledge the challenges brought on by the rapid development of DER, sponsored largely by Government initiatives and not entirely consistent with the efficient development and operation of the distribution network.

That being said, CCP14 took the unusual step, at the request of the AER, to provide specific advice to SAPN regarding a customer-focussed and transparent investment planning process to ensure SAPN's plans were most likely to be understood and supported by their customers. That advice included:

1. that SAPN socialise and validate their forecasts and include information relevant to energy consumers and include discussion on the locational, demographic and commercial assumptions that underpin the assumptions.
2. A 'problem statement' be socialised amongst the industry and energy customers to focus the engagement and assist in stakeholders appreciating the need for a 'solution'.
3. That SAPN present a well-considered optional analysis and risk assessment for the problem and their plans.
4. That SAPN consider a wider range of potential solutions to the impacts of DER growth; including low-cost local approaches and a range of targeted solutions.
5. That SAPN ensure the 'customer view' is integral in this analysis, where the customer impacts and the expected role of customers in any solution are considered and tested through public and specialised engagement. Issues such as direct and indirect costs to customers to participate, technical requirements, contractual matters and similar are to be addressed.

which SAPN is acting on. We discuss this further below.

5.6 Expenditure on Information Technology remains significant at $261m (capital) and $133m (operating), and the alternatives and benefits of such expenditure are not well articulated.

The following table summarises the data on SAPN's actual and proposed significant IT spend over a 15-year period.

$June 2020, millions	2010-15 Actual	Forecast 2015-20	Draft Plan
ICT capex	$165	$313	$261
Total capex	$1,720	$1,713	$1,850
ICT as % of total capex	10%	18%	14%
ICT opex	$68	$92	$133
Total opex	$1,291	$1,331	$1,468
ICT as % of total opex	5%	7%	9%
ICT total as % of totex	8%	13%	12%

Figure 7 - Summary of ICT spend and relative values (Source: SAPN)

We acknowledge that investment in Information Technology (IT) is a significant component in what is largely a data-driven organisation.

SAPN expects to spend $313m on IT in 2015-20, and another $261m in 20-25 – a total of over $570m in 10 years. A source of wide consumer frustration is that such a large level of investment on an ongoing basis is portrayed as 'normal' and 'no choice' or 'recurrent' expenditure, with little obvious concern demonstrated by SAPN on behalf of the customer to ensure that this expenditure is as low as it possibly can be, and that maximum value is extracted from the assets. For customers, such an approach is seen as significantly disempowering.

To some extent, we were left with the feeling that SAPN were keen to invest in 'the best available' solution, with little imperative to seek 'compromise' or less elegant, but also less expensive, approaches to the IT challenges and service objectives.

The options analysis in the workshops was largely binary. Options considered are (a) do nothing, or (b) invest as planned. There is little engagement with customers on scaled options, such as articulating the costs and risks of the deferment of investment, alternative solutions or the real impact to consumers. The counterfactual positions were largely along the lines of 'an inability to maintain acceptable business performance'. We encourage SAPN to reconsider the discussion to reflect more practical and realistic examples of changes to risk and business performance should the IT funding were, say 10, 15 or 20% lower.

Return on IT investment

We see investment in IT as requiring a clear positive impact on business efficiency, productivity, capability, compliance or service to customers.

In IT, SAPN is planning to invest:

- Recurrent (year to year) to 'keep systems operational' - $214m (15-20) then $211m (20-25)
- Non-recurrent (improved or new functionality) - $72m (15-20) then $60m (20-25)

SAPN has noted a benefit to customers of the expenditure in 15-20 as around $70m, and $220m in 20-25.

We ask that the IT investments are directly and transparently linked to demonstrable reductions in the cost to do business.

From the IT deep dive 25 June – Assets & Works programme ($61.6M) - 'Defers approximately $150m to $200m of network expenditure that would otherwise be required to ensure reliability, quality and security of electricity supply'. It will be very useful for SAPN to clarify what work is not needed to be done was / nature of the work / who would do it / risks of not doing / period of payback ?

IT investment to improve business efficiency

It is reasonable to expect that many IT investments are targeted largely at business efficiency, and therefore could be largely 'self-funded' by the distributor as the return of the investment is a lower cost of running the business. We ask: "should customers pay for facilities that assist the business to operate more efficiently, or is that a return on the investment of shareholder funds ?"

Consumers have been told for many years that IT expenditure – also referred to as "digitisation" will be a major source of productivity growth. Given the AER trend productivity data, we remain ot be convinced. And yet SAPN, in common with all networks extols the benefits of IT expenditure. A recent major McKinsey study sought to examine why digitisation has not led to the productivity benefits claimed at the time of the spend[10]. We look forward to seeing a more detailed analysis of the opex dividend that will come to consumers from the large IT expenditure discussed above.

An opportunity to present IT investment needs a 'different way'

We anticipate further difficulty in assessing not only SAPN's IT expenditure needs but also that of other network companies.

A large part of the IT capital proposal is in the area of 'business as usual' asset replacement of equipment and applications that are considered to have reached the end of their service life. We encourage SAPN to take a slightly different approach to presenting these IT requirements, inline with recent work by the AER around asset replacement planning.

We consider a powerful step forward in presenting IT capital needs would be met by separating the facts underpinning the asset retirement decision from that of decision 'what to do about it'. For example:

a) Highlighting the systems that are being considered as 'end of life'

b) Being explicit as to why these systems have reached their economic or technical service life, in terms of failure to fulfil the required function in terms of risk to business function and costs to maintain.

c) Present the options that are available to extend the life of the asset and be clear why the decision to replace outweighs the decision to seek ways to extend the life of the asset.

d) When a replacement decision is taken, demonstrate why the chosen path is the most efficient

We acknowledge that SAPN is not required to present the IT replacement in this form, however doing so has the potential of the investment being better understood, and hopefully supported, by customers.

5.7 More information on the impact on the Regulated Asset Base (RAB) will assist in assessing the long-term impact of the plan.

[10] See McKinsey Global institute "Solving the Productivity Puzzle" February 2018
https://www.mckinsey.com/featured-insights/meeting-societys-expectations/solving-the-productivity-puzzle

SAPN did not include any data on RAB in the Draft Plan. SAPN have subsequently advised[11] that the RAB will increase by 7% in real terms from $4,339m at the end of the current period to $4,641 at the end of the next period on 30th June 2025.

We look forward to a fuller justification of the RAB increase given the subdued demand outlook. As we noted above, we agree with SAPN on the difficulty of removing assets from the RAB once that are in it. Which is why, given consumers, particularly non-solar consumers, who bear the risk of falling grid demand only want essential capital going not the RAB.

5.8 A commitment to the 2018 Rate of Return (WACC Guideline) is expected.

We note that SAPN has calculated the WACC in its Draft Plan in accordance with the AER's recently published 2018 Draft Rate of Return Guideline. We welcome this as the final 2018 Guideline will apply to SAPN's regulatory proposal and will be binding.

It is interesting to note that the AER's Draft WACC Guideline has been subject to considerable criticism from Spark Infrastructure, the 49% owner of SAPN, focussing on the proposed lower equity return component and gamma[12] and strongly opposed by SAPN in its combined network submission to the AER Draft Guideline[13]. The table compares the proposed price paths under the AER Draft Guideline and the 2013 Guideline which approximates what Spark/SAPN would prefer. Total revenue would be ~$164m or 4.2% higher under the preferred approach. Applying the 2013 Guideline would result in constant real prices over the 2020-25 period.

		% Real Price Change	
	WACC	Year 1	Years 2-5 – each year
2018 AER Draft	5.55%	-3.9	0
2013 Guideline	5.96%	0	0

Figure 8 – Estimated Impact of the Rate of Return Guideline on prices (Source SAPN., CCP14 analysis)

In correspondence subsequent to the publication of the Draft Plan, SAPN have argued that using the Draft Guideline "…is more representative of the likely outcome for customers than the soon-to-be-superseded 2013 Guideline."[14] Given this there are two matters that we would like to have seen in the Draft Plan:

1. A clear commitment that the outcomes from the final 2018 WACC Guideline will be incorporated into its Regulatory Proposal in the same way as it does on p. 61 for the outcomes of the current corporate income tax review

[11] Communication with SAPN 6th September 2018

[12] See the Network Shareholders Group presentation at the AER Forum on 2nd August 2018 https://www.aer.gov.au/system/files/NSG%20-%20Public%20forum%20presentation%20-%202%20August%202018.pdf

[13] SAPN et al submission to the AER https://www.aer.gov.au/system/files/Joint%20Energy%20Businesses%20Final%20Rate%20of%20Return%20Submission_Redacted.pdf

[14] Correspondence with SAPN 6th September 2018.

2. Clear communication of the relative contributions in the revenue changes in 2020-25 from 2015-20 and the price path in 2020-25 from factors outside of SAPN's control (e.g. WACC review and lower interest rates) and those within SAPN's control (new capex and opex). As noted above the latter is only a small contributor.

5.9 Clarity on the calculation and nature of the Incentive schemes is needed.

The Draft Plan notes on page 60 that the net effect of the four incentive schemes is an $8 million carry over into 2020-25. It would be more helpful to consumers to break this up so that they can understand where the balance of these schemes falls. For example, the CESS Overview Fact Sheet that SAPN provided in the Deep dives listed the CESS carry over as around $40 million. As this has now been reduced to $8 million, it would be helpful to outline the specific contributions of each of the EBSS, STIPS and DMIS schemes.

We repeat our observations from the opex comments below, that the EBSS should only be available if the AER concludes that the 2018-19 base year is both representative and efficient.

6. Comments on SAPN's planned operating expenditure (Opex)

The table below summarises recent trends in opex expenditure expressed in $2020 for ease of comparison. After spending $1,256m in 2010-15, SAPN originally sought $1,679m for the current 2015-20 regulatory period, revised down to $1,563m. The AER's final decision was for $1,376m, an 18% reduction on the original request and 12% on the revised request. SAPN's latest forecasts are for $1,331, which is a 21% reduction on their original request.

$2020m	**2010-15**	**2015-20**	**2020-25**
SAPN submission (original/revised)		$1,679/1,563	
AER Final Decision Allowance	$1,256	$1,376	
Actual/forecast	$1,291	$1,331	
Draft Plan			$1,468
% change over 2015-20 forecast			+10.3%

Figure 1 - Operating Expenditure (OPEX) summary (Source: SAPN, CCP14 analysis)

The Draft Plan has a 10.3% real increase in opex for the 2020-25 period, in a time when forecast energy demand is falling. The Draft Plan provides for zero productivity improvement for opex, consistent with current the AER assumption.

Our interpretation of Chapter 2 of the Draft plan suggests that "as SAPN ranks high in productivity comparisons, it has less ability than lower ranking networks to further improve its productivity". This view is confirmed by SAPN's response to consumers views expressed in the engagement earlier this year to have an opex productivity factor (p.56):

> *"In our engagement program earlier this year, customers and stakeholders sought to apply an additional productivity growth factor to reduce costs.*
>
> *We do not support this approach as further productivity growth must represent industry-wide efficiency gains. As a leader in efficiency, it will be more difficult for SA Power Networks to achieve additional, across-the-board productivity gains than less efficient distribution businesses, and we will be penalised if we cannot meet those gains. We have not applied any*

further productivity growth factor in our Draft Plan, but we will continue to strive to achieve further efficiencies to deliver on our operating obligations at a cost lower than our regulatory opex allowances and share those benefits with customers through the EBSS.

We will continue to explore ways to respond efficiently to any current or new drivers of our operating expenditure, through cost saving initiatives…"

So while SAPN's opex productivity has improved over recent years, SAPN is not prepared to take a risk that it will continue and hence offer a productivity improvement. SAPN is asking consumers to rely on EBSS where consumers receive only 70% of the productivity benefits.

By contrast, other networks currently engaging with the AER on the allowances of their next reset period have responded to consumer submissions by offering opex productivity improvements independently of what the outcome of the AER review might be[15]. These include Tasnetworks Distribution which had higher opex productivity than SAPN over 2013-2016 and ranked just below SAPN in 2015-16[16] It offered the following productivity improvements[17].

Table 9-12: Distribution productivity improvements per cent (real) and annual savings (June 2019 $m)

Input	2019–20	2020–21	2021–22	2022–23	2023–24
Annual distribution cost savings (%)	-1.88%	-2.93%	-4.43%	-5.90%	-7.39%
Annual distribution cost savings ($m)	-1.6	-2.5	-3.8	-5.0	-6.4
Cumulative distribution cost savings for the period (%)	-1.88%	-2.41%	-3.09%	-3.79%	-4.52%
Cumulative distribution cost savings	-1.6	-4.1	-7.8	-12.9	-19.2

Looking at particular opex components, we do not see how the Draft Plan's proposed 1% increase in real labour costs is consistent with[18]:

"…continually striv(ing) to reduce opex and improve benchmarked outcomes."

We consider any real increase in labour costs as indicative of a failure of EBA negotiations to provide sufficient offsetting productivity improvements for wage rises. As the ACT concluded in its decision to reject the SAPN argument that complying with the EBA is a regulatory obligation[19]:

"The NEO indicates that the overarching objective is to ensure the efficient investment in and operation of electricity services for the long-term interests of end users. The NEO is supported, among other things, by the opex criteria which direct attention to whether opex costs are prudent and efficient.

The contents of an EA (at least at the point of its establishment) is something which is negotiated by SAPN management and the employees covered by the EA. Despite the best efforts of a DNSP (like SAPN), there is the capacity for an EA to include terms (and

[15] Essesntial, TasNetworks Distribution, Energex and Ergon

[16] See Draft Plan p. 12

[17] See TasNetworks "Tasmanian Transmission Revenue and Distribution Regulatory Proposal – Regulatory Control Period 1 July 2019 to 30 June 2024" 31 January 2018 p. 154 https://www.aer.gov.au/system/files/TN-Transmission%20and%20Distribution%20Regulatory%20Proposal%202019-2024_2.pdf

[18] Draft Plan p. 55

[19] Application by SA Power Networks [2016] ACompT 11 [527] at p 124

corresponding costs) that are not conducive to meeting the NEO, for example because a DNSP needs to accede to employee demands.

Ultimately an EA is the product of negotiation and there is considerable discretion on SAPN on the costs associated with complying with the terms of an EA. It is not necessarily benchmarked to provide the necessary comfort that EA costs are efficient. The Tribunal does not accept SAPN's submission that the arms-length negotiation of its EA is a substitute for benchmarking or other appropriate means for testing its costs."

We do not believe that consumers should bear the cost of a network's failure to obtain productivity improvements to offset wage rises. It should be borne by the network's shareholders.

We do not necessarily agree with this logic:

"*We believe that our delivery of operating costs below our regulatory allowances while we continue to meet service standards in the current period, and our benchmarked position as an efficiency leader, confirms that our base year opex for 2020–2025 is efficient."*

Continual improvement against AER allowances may also be an indication of an overly generous allowance. The EBSS can also provide an incentive to obtain higher base year costs level to increase the networks share of any improvement. The EBSS was intended to equalise incentives over time and not create a bonus for DNSPs. "Soft" assumptions on productivity mean that the expected value is positive and inconsistent with LTIC. We believe that the expected value of the EBSS should be zero.

It is the recent improvement on opex productivity across networks that has led the AER to undertake its review to see if its zero assumption is valid. If this is an indication of the efficiency frontier moving out then the zero assumption should change in assessing the base cost for an efficient and prudent operator. Consumers should get 100% of the benefit of the frontier moving, not 70% under EBSS as SAPN is proposing. Networks are then free to use EBSS for further gains beyond the AER assumption.

SAPN is unprepared to bear the risk of not achieving productivity gains at the same time as making numerous statements in the Draft Plan about its focus on improving efficiency. At the same time SAPN wants consumers to bear all the risk on the other side eg the cost of step changes.

7. Comments on SAPN's planned Capital Expenditure (Capex)

CCP14 has a number of overarching principles to support capital investment, being:

1) a demonstrated commitment to a reduction in the RAB, with a goal for the capital investment to be less than the depreciation;
2) ensure investments in non-network assets, in particular IT, provide demonstrable benefit to consumers;
3) ensure investment leading to improved or changed performance or services has clear and informed consumer support;
4) identify under-expenditure in the current period that is not efficiently carried forward;
5) aggressively continue to pursue efficiencies, cost reductions and productivity improvements;
6) changes in design or risk approach that leads to reduced cost (e.g. overhead lines in lieu of underground);
7) use of new technology leading to clear cost reductions or expenditure deferral;
8) network performance agreements with customers enhancing non-network options;
9) a staged approach to asset replacement;
10) a focus on the reduction in capitalised overheads; and
11) per-unit efficiencies for assets such as vehicles, buildings and mobile technology.

SAPN's Proposed Investment for 2020-25

SAPN are proposing a total capital expenditure in 20-25 of $1.850B, an increase of $137M (8%) on the forecast expenditure in 2015-20, and $230M less than the 2015-20 regulatory allowance.

Customer connections

The capex workshop noted "*connections expenditure in 2020-25 is forecast at similar levels to current costs, based on independent forecasts".* The workshop was advised that customer connections expenditure was planned to be $164M, very similar to the 15-20 forecast.

The Draft Plan requires an investment in capital contributions of $196M, which is $32M higher than the earlier advice and $29M (17%) higher than this period's requirement. We will require further information as to why this change is needed.

Augmentation

An opportunity exists to reduce overall expenditure on network augmentation presented by the flat demand growth, as seen in the $87M (-34%) reduction in demand-related augmentation investment. We note that, unlike most other utilities, SAPN elected not to highlight the magnitude and locational nature of demand growth requirements by presenting fairly detailed demand forecasting to the community workshops, focussing more on issues such as reliability. This lack of concern regarding network capacity is reflected in the summary tables and RIT forecasts in the SAPN DAPR.

SAPN's approach to probabilistic network risk and sensitivity impacts is not clear We acknowledge that SAPN outlined their approach to risk in the engagement, and we recommend that SAPN consider the impacts to customers should the risk parameters be varied. Essentially, the counterfactual arguments

are not clear to us at this stage. Therefore, at this stage we cannot support the proposed level of investment in network augmentation.

The reduction in requirements for demand related augmentation is almost exactly taken up by the additional expenditure for the proposed 'targeted investments' such as strategic investment, targeted additional reliability improvement projects ($37M), targeted additional safety-related projects ($38M) and an increase in the allowance for the government initiative Powerline Relocation Enhancement Programme (PLEC).

As discussed elsewhere in this response, we query the need and support for these additional targeted programmes.

Replacement Capital

We have concerns regarding the significant underspend on repex in 2015-20, followed by a similar increase proposed for 2020-25. We will defer to the AER and its significant modelling capability to consider the repex requirement.

Non-network capital

IT is discussed elsewhere in this report.

We do not believe that sufficient information has been presented regarding the proposed expenditure on fleet, property and telecommunications largely as the counterfactual position Is not clear. Information that supports 'what if a different approach was taken' understanding by consumer groups would greatly assist in appreciating why the level of investment is appropriate and optimum. This information is needed before we can support these aspects of the Draft Plan. We are aware that these issues have also been raised by SAPN's CCP.

8. Consumer and stakeholder engagement

CCP14 has had many opportunities to observe the SAPN engagement including:

- a Phase 2 Directions Workshop
- participation in all Deep dive workshops
- SAPN CCP meetings
- individual Reference Group meetings
- technical and modelling meetings with SAPN and the AER and
- the current SAPN CCP engagement on the Draft Plan.

CCP14 commends SAPN for its early engagement and for releasing a Draft Plan of its regulatory proposal several months prior to lodging the draft revenue proposal with the AER in January 2019. The program set out on pages 18 and 19 of the Draft Report represents a lot of resources and commitment by the stakeholder relations team and the former and current SAPN executives who have fully participated in the engagement program.

Objectives of early engagement

This style of early engagement is consistent with comments made by Paula Conboy to the ENA conference in July 2017 when the AER first discussed AER 2.0. CCP14 believes that there are 4 aspects to a successful early engagement strategy:

1. the first is 'no surprises' so that stakeholders understand what will be in SAPN's proposal prior to it being lodged.
2. The second is for stakeholders to give feedback to SAPN about its proposals and for SAPN to respond to that feedback by making changes to its proposal. SAPN's preliminary proposal from November 2017 has evolved from CPI+2% in year 1 with CPI in years 2-5 to its current proposal of CPI-3.9% followed by CPI. However, most of the proposed price reduction is due to the AER's Draft WACC guideline.
3. Ideally the draft revenue proposal that will be lodged by SAPN in 2019 would be largely capable of acceptance in that it would be supported by stakeholders and SAPN's customers as being in their long-term interests.
4. The AER would adopt a more top down triaged approach to a draft revenue proposal that had stakeholder support as being in the LTIC.

The positive aspects of SAPN's early engagement are that issues of concern to customers have been highlighted early. Capex examples include the investment in the network of the future and the ongoing IT investment. Opex examples are the lack of productivity efficiencies. There has also been a significant focus on SAPN's demand forecasts, which has highlighted inadequacies in the transparency of AEMO forecasts.

Stakeholder involvement

Stakeholders including the AER's technical advisory team, have made a very large investment in early engagement with SAPN. SAPN's engagement involved a lot of time from its executives with detailed slide packs and information fact sheets. Customer advocates and other stakeholders, including CCP14, have limited resources and attending multiple deep dive sessions is resource intensive. The result is that SAPN is now fully aware of the issues that its stakeholders have with its Draft Plan.

It is not as clear to CCP14 that stakeholders have reaped the same benefits from their investment in this program with the current Draft Plan still effectively proposing a price increase of +.7% above CPI (without WACC). This does not seem consistent with the CEO's Foreword to the Draft Plan that what SAPN has consistently heard is that SAPN should be doing 'more for less'.

Expectations from the next steps in engagement

SAPN is currently seeking feedback from a wide range of stakeholders about its Draft Plan. The purpose of this engagement is for SAPN to hear concerns about the Draft Plan. SAPN has publicly stated that it does not intend to further engage with stakeholders about their concerns prior to lodging the draft revenue proposal in January 2019. CCP14 believes this is a lost opportunity and is certainly not consistent with the approach being taken by some other DNSPs. For example, EQ who is on a similar timetable to SAPN, also has a draft plan open for consultation. EQ has advised CCP 14 that it intends to consult further on issues of concern to stakeholders with the objective of seeing if any of those concerns can be addressed prior to lodgement.

In our view an approach where engagement and collaboration are maximised prior to lodgement has the greatest chance of leading to a draft revenue proposal that would be largely capable of acceptance

in that it would be supported by stakeholders and SAPN's customers as being in their long-term interests.

SAPN has set out the feedback from its customers about the need to keep prices down on page 22 in the Draft Plan. Part of the feedback is to show that SAPN has avoided or deferred any unnecessary expenditure. This means SAPN needs to justify to its customers that the Draft Proposal:

- does not contain one single dollar more investment than is necessary
- delivers benefits that are in consumers interest and
- is equitable between its different customer groups.

SAPN can only demonstrate this if it engages with stakeholders about the risks to the network reliability if the proposed expenditure is reduced. This is even more critical where SAPN is again forecasting not to spend all of its allowed revenue in 2015-20.

CCP14 believes this requires SAPN to collaborate in discussions with stakeholders about its Draft Plan and to contemplate further changes to its draft proposal.

SAPN Consumer Consultative Panel

CCP14 is currently observing the engagement between SAPN and the SAPN CCP about the Draft Plan. We welcome the support that SAPN has provided to their CCP to prepare that submission.

Using the Draft plan as a starting point, SAPN's CCP proposed to SAPN an approach of ongoing engagement to try to achieve as much agreement as possible prior to the proposal submission in January. As mentioned above SAPN has advised the SAPN CCP that its response to the Draft Plan will be an input to its further internal refinement of its plans prior to lodgement but will not be the basis for further engagement by SAPN

So far, the main feedback we have observed the SAPN CCP giving to SAPN has been that the proposal:

- does not represent more for less
- does not clearly explain the impact of the proposal on non-solar customers
- is inaccurate as it refers to average residential bills when non-solar customers have been experiencing significant price rises
- cannot build trust with consumers in the way that it is presented – for example referring to the limited reliability metrics when compared to State-wide blackout issues and referring to average residential bills
- does not adequately set out impacts on RAB, carry forward EBSS allowance
- is not based on transparent and realistic demand forecasts
- does not set out benefits to all customers from investing in DER and the network of the future
- is not commercially realistic as there is no opex efficiency
- has recurrent IT expenditure of $40m per annum with no offsetting efficiency
- includes a capex proposal that is 10% above the current forecast when demand is flat or declining and
- is not capable of acceptance.

CCP14 believes that SAPN has an opportunity to work with its SAPN CCP, CCP14 and other stakeholders in a collaborative way between now and January 2019 to further amend the draft proposal and show that SAPN has incorporated the feedback of its customers into its Draft Plan. We are aware that SAPN intends to inform its CCP of the main themes of submissions in an upcoming consultation and CCP14 encourages SAPN to reconsider its decision not to try to reach agreement on outstanding concerns prior to January 2019.

Consultation on Network of the Future

One area of particular focus for CCP14 has been the proposed investment in the Network of the Future. As referred to in section 5.5 above, we wrote an advice to the AER setting out our concerns about this issue on 29 June 2018[20] and SAPN responded on 2nd August 2018[21] .

We commend SAPN for highlighting both the strategy behind this investment and the cost of it. We repeat what we said in our advice to the AER in June:

> "*CCP14 congratulates SAPN for raising this important issue in the context of the community engagement for the upcoming regulatory reset. We view the public discussion of this issue as a positive aspect of early engagement.*
>
> *We also recognise that SAPN is one of the first DNSPs to address this challenge in the wider context of the proposed Distribution System Operator (DSO) model currently being discussed across the industry. Consequently, we are keen to encourage and support SAPN in exploring viable and customer- aware responses to the technical issues it faces, as these responses are likely to be a blue print for other DNSPs across the NEM*."

Our specific advice to the AER was:

> *"SAPN undertake a more a transparent, wide ranging consideration of the drivers, risks and range of potential solutions to high distributed generation penetration that present more appropriate outcomes for energy consumers.*
>
> *The AER should separately analyse the AEMO research and forecasts to test and validate AEMO's concerns about NEM wide implications from increasing penetration of DER."*

Since our June advice both SAPN and AEMO have met with the AER. Despite requests from the AER, SAPN and other stakeholders, AEMO has not yet released the modelling that underpins its forecasts.

SAPN provided a detailed response to our advice to the AER on 2 August. SAPN advised both CCP14 and the AER that it would not seek to rely as much on the AEMO forecasts when developing its demand forecasts by running more sensitivity analysis. SAPN has also rethought its strategy and advised the AER that it no longer intends to build a comprehensive LV model but could instead build a scaled down template model relying on 10% of its network that could then be extrapolated. This involved a reduction in investment and we support the goal of publishing constraints on the SAPN LV

[20] See https://www.aer.gov.au/system/files/Subpanel%2014-%20Response%20to%20SA%20Power%20Networks%20approach%20to%20the%20challenges%20of%20the%20high%20penetration%20of%20embedded%20generation%20as%20part%20of%20their%202020-25%20Regulatory%20Proposal%20early%20enagegement%20-%2029%20June%202018.pdf

[21] See https://www.aer.gov.au/system/files/SAPN%20response%20to%20CCP14%20advice%20to%20AER.pdf

network as this should lead to different VPP investment strategies as well as market based non-network solutions to respond to local constraints caused by DER.

CCP14 also strongly encouraged SAPN to take its revised DER strategy to its own Renewable Reference Group to seek their feedback. On 11 September we observed the detailed presentation by SAPN to its RRG on the modelling and assumptions underlying the $37m capex and $10m opex investment discussed in chapter 5 of the Draft Plan. Two things concern us from this meeting.

1. SAPN executives clearly stated that the demand forecasts were based on the most recent AEMO forecasts with the additional South Australian Government and Tesla battery initiatives added in. The scenarios being modelled appear to depend significantly on AEMO's weak, neutral and strong forecasts with consideration of SA Government battery initiatives. CCP14 remains very concerned that the modelling underpinning AEMO's forecasts has not been made available publicly or at the very least to the AER.
2. SAPN told the RRG that the reduced $37m investment was not just to build an LV template model and data capture capability, rather it also involved dynamic curtailment capability. The RRG were told that $27m was for the model to provide visibility and that $10m was for curtailment. Again, this was contrary to the discussion that SAPN had with the AER and with CCP and is also inconsistent with SAPN's response to our 29 June letter. The SAPN response dated 2 August states:

> *"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*
> - *Contractwiththirdpartiesthathavecustomer-sideresourcesundertheircontrol 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. "*

CCP14 raised our concerns about this inconsistency with SAPN. The response from SAPN was:

> "*There is no inconsistency between what was presented at the RRG and in the SAPN response dated 2nd August. We accept we could have done more to ensure the explanations were understood by stakeholders.*
>
> *Our proposal costing and discussions have always included both:*
>
> - *visibility and modelling, to understand the physical capacity of the distribution network to transport energy generated at the premises in a given location at a given point in time*

- *Publication of dynamic export limits, so that embedded generators can operate safely within the technical envelope of the network assets*

The 2 August response intended to make it clear that dynamic export limit capabilities are not a direct control function, but an extension of the way that embedded generation is managed today.

All customers with solar PV and battery storage are subject to export limits today: they are required to limit their export power to 5kW or below at all times. This static limit does not allow for the fact that the actual capacity of the network varies considerably with time and location. With dynamic export limits we hope to be able to provide a variable limit that more accurately reflects the true capacity.

Not only do we see this as an efficient mechanism to ensure efficient DER integration and real time network performance, but it will also provide the information necessary for procurement of non-network solutions and to support informed choices by our customers on where to connect, network investment opportunities, etc.

Feedback from our ongoing DER integration and technical working groups, and during the recent Open Energy Networks workshops convened by AEMO and ENA identified the ability for DNSPs to determine and publish hosting capacity signals as one of the highest priority capabilities required to support the efficient DER transition for the benefit of all customers.

Aggregators represented as part of these bodies indicated that their intended mechanisms to provide non-network solutions involve real time optimisation around various value streams, making signalling the need for procurement of services by the DNSP (i.e. leveraging our dynamic constraint calculation capabilities) an integral part of their optimisation process."

We remain concerned that SAPN needs to seek lower cost alternatives to the 'big red button' that the AEMO / ENA Open Networks position appears to be driving. We also believe that SAPN's customers want to be reassured that SAPN is looking at this from their point of view – ie what are the benefits (for all customers, not just those with DER), will the value proposition be enough to ensure participation? If this investment is made by SAPN, what is it's likelihood of adoption by customers?

Some of our other issues are:

- Whether the assumptions that underpin the modelling will be released for scrutiny by informed consumers and industry to assist in customers 'signing onto' the position that there is a problem that needs to be addressed?
- Is the 'problem that is to be addressed' and the benefit of doing this clear and understandable by customers? Have the risks been considered?
- Have all local solutions (AS4777 inverter controls, tariff incentives, connection agreements, incentives for self-consumption) been fairly considered?
- Have alternatives to central control of curtailment, such as incentives for mid-sized systems to limit export, been considered?
- Does the 'social benefit' to all energy consumers, including the 50%+ who will not invest in DER, justify the fact that all customers will need to pay for this initiative?

CCP14 encourages SAPN to continue its engagement on this DER proposal.

9. Pricing: DM and Tariff Structure Statement

Pricing Principles

As SAPN notes in Chapter 9 of its Draft Plan, SAPN's 20-25 TSS builds on a set of tariff principles developed by SAPN customers for the 2017-20 TSS. CCP14 agrees with the4 principles: empowerment, fairness and equity, simplicity and compliance. CCP has contributed to the development of Pricing Directions Principles and a copy is attached. These principles have been prepared in conjunction with ECA, PIAC and TEC and endorsed by those organisations as well as the AER TSS team and most recently by the ACCC in its Final Report in the Retail Electricity Pricing Inquiry (Final Report).[22]

The purpose of cost reflective tariffs is to send a signal to retailers (and ideally to the end customers) of the impact (cost) of their use of energy on the distribution network to try to bring about behavioural change, which will in turn defer investment. We recognise that each network has different issues to manage and hence different signals need to be sent through tariffs and DM strategies. As SAPN notes in its Draft report on page 65, it has largely ceased managing increasing peak demand since 2009. Its main challenge is preventing the need to increase network capacity to cater for localised constraints in its network for extra solar generation. As noted in the Pricing Directions Paper:

> "*To the extent that two-way flows have a different impact on network costs, this should be reflected in the pricing (including network support payments) for those flows. The objective should be to price access to the distribution networks in a manner that:*
>
> - *Provides signals for renewable capacity to locate in areas and be operated in a manner that benefits the network where possible*
> - *Fairly reflects the costs imposed on the distribution network as well as the benefits that it may provide."*

The ACCC concludes in its Final Report that the progress of cost reflective tariffs has been too slow. It notes:

> "*The above factors mean that there is a risk that, if left unchecked, the incentives under current tariff structures will result in higher network charges for all customers as networks are required to undertake potentially avoidable investment. These networks costs may also need to be recovered over a smaller volume of total electricity consumption due to incentives on customers to minimise their consumption (including through the installation of solar PV systems). These additional costs will be borne disproportionately by those customers unable to access new technology or services to manage and reduce their electricity supply.*
>
> *In the short term, adoption of cost reflective pricing should lead to a fairer distribution, rather than a reduction, in overall electricity costs. This will include some customers paying more than under current tariffs. However, there are inherent inequities in current pricing structures as well, with some customers already paying more than they should because of the cross-subsidies in current tariffs. Cost reflective pricing would mean that existing cross-subsidies in favour of high peak usage customers are unwound. As such, more cost reflective tariff structures should lead to fairer outcomes, as those paying more will be doing so because of the*

[22] ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – Final Report, June 2018

demands they place on the network." (at page 180)

SAPN's 4 TSS principles are consistent with the ACCC's recommendations 14, 15 and 22 as well as the attached Pricing Directions Principles. In reviewing chapter 9 of the Draft Plan, CCP14 has considered if SAPN is doing enough through its draft TSS proposals to address the excess solar energy challenge and manage pricing inequities between its rapidly increasing solar customers and non solar customers.

As we discussed in section 7 above, CCP14 has been observing the engagement discussions between SAPN and the SAPN CCP. An initial discussion about tariffs was held on 11 September and a further discussion is scheduled for 24 September after our response needs to be given to SAPN. CCP14 also attended the Renewables Reference Group meeting on 11 September. The main feedback given to SAPN by the SAPN CCP about both the form and content of its Draft Plan when dealing with pricing and tariffs was:

- the average reduction of $37 in residential bills does not distinguish between solar and non-solar customers. Non-solar customers have seen very large rises in their bills and the current presentation is misleading;
- there is a lack of confidence in SAPN's demand forecasts. SAPN executives confirmed that its forecasts are based on the most recent AEMO forecasts for PV uptake, batteries and very limited EV penetration by 2025. Members of the SAPN CCP expressed serious concerns about the forecasts and the fact that they did not include consumer response;
- if SAPN is successful in achieving behavioural change through its tariff and DM initiatives and if this is not adequately factored into the SAPN forecasts this will result in further inequity through rising bills for non-solar customers ; and
- faced with falling demand SAPN should not only be avoiding increased capex spending on the network, it should be looking for opportunities to reduce its network. Demand may continue to decline especially with the South Australian Government subsidising the roll out of batteries during the 2020-25 period and customers should not be paying for unsustainable investment.

Similar concerns were expressed in the Renewable Reference Group meeting that non-solar customers were being asked to fund the Network of the Future investment discussed in chapter 5 of the Draft Plan without the clear benefits of the claimed lower electricity wholesale prices being explained to them.

CCP14 believes that SAPN should use the 2020-25 TSS to maximise shifting customer behaviour to reduce the impact of the excess solar energy.

SAPN should provide greater transparency of how tariff response is reflected in its modelling and in its forecasts. This is very important as SAPN is proposing investment of $37m and $10m in opex to build a LV monitoring model to provide visibility of constraints caused by the reverse flow in the middle of the day. As SAPN notes on page 65 unless it changes consumers' behaviour either through cost reflective pricing, publishing constraints on its network to influence where new VPPs can be accommodated or through rule changes allowing them to price export energy at its true cost, then SAPN will need to increase network capacity to cater for localised coincident peak of extra solar generation during the solar trough. The inequity and unsustainability of this is clear given that non-solar customers would be expected to fund this enhanced capacity. This was also discussed by the ACCC in its Final Report:

"*According to modelling conducted for the AEMC in 2014, installing an air conditioner adds $1000 to annual network costs, but the household using the system only pays $300 of this through higher bills. Similarly, the modelling found that a customer using an average-size north-facing solar PV system will save about $200 a year in network charges, but will only*

reduce network costs by $80. The remaining cost in both cases is met through higher charges on other users." (See page 179)

CCP14 supports the shift to 2 off peak windows between 1-6am and the solar trough in the middle of the day 10am-3pm. CCP14 would encourage SAPN to make the prosumer tariff being targeted at VPPs, as a mandatory tariff for all solar customers after 12 months of smart meter data. We believe this will achieve behavioural response quicker than making the prosumer tariff an opt out tariff with the opt out to the residential time of use tariff currently specified as the mandatory tariff.

For those customers with a type 6 meters we support the modest increase in the fixed charge by no more than $10 per annum. We also support the proposed reallocation of costs between business and customers as cross subsidies are inherently inequitable.

We note that SAPN has proposed 2 potential tariffs both of which we support. The Riverland DM strategy is an excellent example of the strategies discussed by the ACCC in chapter 8.4 of its Final Report and in the attached Pricing Directions and we commend SAPN for integrating localised DM initiatives as part of the TSS. SAPN responded to feedback from retailers and customers about its proposed Critical Peak pricing tariff and removed it from its tariff proposals. In its Final Report the ACCC supported demand tariffs as being more cost reflective than time of use. The ACCC stated: "*While more complex than existing flat rate or ToU tariffs, demand tariffs represent a good balance of cost reflectivity, simplicity and price stability for an initial process of mandatory assignment*."

We encourage SAPN to seek to expand its demand tariffs to be an agreed combination tariff notwithstanding the greater complexity as removing inequity between customer classes in South Australia is very important and retailers have different strategies for packaging the signal to customers.

CCP looks forward to working with SAPN and ECA on the development of its TSS.

ATTACHMENTS FOR REFERENCE

A1. CAPEX – Points for discussion

SAPN CAPEX							
$M, 2020$	2015-20 Allowance	2015-20 Forecast	2020-15 Draft Plan Sept 18	Variance - forecast to allowance 2015-20		Change draft plan to 15-20 f'cast	
Repex	761	614	726	-147	-19%	112	18%
Augex	546	453	457	-93	-17%	4	1%
Demand Driven	355	255	168	-100	-28%	-87	-34%
Reliability	49	36	73	-13	-27%	37	103%
Environment	24	10	10	-14	-58%	0	0%
Safety	17	45	83	28	165%	38	84%
Strategic	51	62	68	11	22%	6	10%
PLEC	50	45	55	-5	-10%	10	22%
Customer Connections	207	167	196	-40	-19%	29	17%
Gross		489	589	489		100	20%
Cust Contribution		-322	-393	-322		-71	22%
Non-Network	566	471	472	-95	-17%	1	0%
IT	299	308	261	9	3%	-47	-15%
Fleet	135	92	108	-43	-32%	16	17%
Property	81	49	76	-32	-40%	27	55%
Tel & Comms	16	2	8	-14	-88%	6	300%
Tools & Plant	35	20	19	-15	-43%	-1	-5%
TOTAL	2080	1705	1851	-375	-18%	146	9%

Asset Replacement

Note: Repex is likely to be underspent significantly by 19% ($147m) in 2015-20 and is proposed to come back in 20-25 to a similar level as that allowed for in 15-20 ($726m). I believe this assessment will be well dealt with by the AER, and from a CCP viewpoint we do not proposed to make a specific issue of repex.

1. Repex in underspent this period, and SAPN advise this is due to storms and regulatory uncertainty. Has any work that was planned (and funded) for 15-20 but not done due to the reasons given for the under-expenditure (storms, uncertainty) needed to be carried over into the 20-25 programme?
2. Has there been any demonstrable negative impact, such as not meeting network performance targets or more safety incidents that may have occurred as a result of the repex underspend?

Augmentation

3. Proposed non-demand driven Augex (Reliability, etc.) has increased by $91m (46%) from the forecast spend in 2015-20. What justifies this increase?
4. We note that there is an increase in the expected spend in customer connections in 20-25. Can SAPN advise the relationship between falling augmentation expenditure and increasing connection costs? Supporting evidence behind the demand forecast such as substations with load at risk or consultant's advice regarding customer growth would assist.
5. The increase in complaints from customers regarding quality of supply is noted. Under what category is this issue being addressed?
6. Has the connection performance or service to customers, such a connection times, degraded over the current period?

Connections

7. What is the nature of this increased investment in customer connections over and beyond current period rates? Could SAPN provide further information from the referred-to consultant's report regarding customer growth?
8. How does this growth sit with the fact that upstream augmentation continues to fall significantly? Is there further information on asset utilisation, in particular the growth areas such as Mt Barker West and Gawler East?
9. Is SAPN planning any change to its Customer Contributions policy?

Information technology

10. Can SAPN expand on how the IT expenditure has reduced the Replacement Capital investment by $200m? Is that $200m off the planned 20-25 spend, suggesting that if repex was done 'the same way it is being done now, SAPN would require $926m, being a 50% increase on the amount spent on repex in 2015-20?
11. Are there other areas of expenditure that are reduced as a result of the IT investment benefits?

Reliability, Safety & Environment

12. Q7. Could SAPN show some planning reports to demonstrate the approach, risk position and cost effectiveness of a number of planning development proposals?
13. Reliability investment doubles with an additional $37m to $73m, which includes $37m reliability improvement, $17m to 'Harden the network' and $19m to address the worst performing feeders.
14. The ESCOSA survey found that affordability was much more important that reliability, where the draft report notes (p. 2): "The Commission's draft decision sets out that, for the 2020 – 2025 period, network reliability performance standards will apply to ten region-based categories. Targets will be set to maintain reliability at current levels, rather than improve or

reduce performance. This approach is supported by results of a customer survey showing that 73 percent of customers are satisfied with current reliability outcomes, and the results of economic assessments which show no clear economic benefit in setting targets to improve performance."

15. Q8. Given ESCoSA has been fairly unremarkable with their review and suggesting SAPN is likely to be largely compliant with new reliability targets, why is the current spend of $37m on reliability improvement in total not sufficient? Are there KPIs or community advice available to support this additional expenditure?
16. Environment – no issues. It would assist the case by confirming the EPA or regulatory position driving the work, considering options and demonstrating the response is the most efficient.
17. Safety – this is a significant increase from the 2010-15 spend of $8m, to the 15-20 allowance of $17m, to the forecast expenditure this period of $45m, to a planned investment of $83m in 2020-25. SAPN has not made it clear what is behind the change in terms of performance indicators, changed regulatory obligations or other drivers of this significant escalation in expenditure.
18. What is behind the significant escalation of the safety budget? Can SAPN point to the KPIs and performance requirements that underpin the change?
19. Q11. Could SAPN provide more detail regarding the $24m protection upgrades and $40m substation equipment investment? How will a positive outcome be measured?

Strategic

20. Strategic Augmentation – It is noted that half $31m is the DER modelling and establishment of an LV system model. The other half is an ADMS (Distribution Management System) upgrade.
21. What is the purpose of the ADMS upgrade, and is the upgrade discussed the wider IT strategic plan?
22. PLEC – no issues, recognising it is a legislated requirement. Can SAPN confirm the reason why the PLEC allowance has increased from $50m in 15-20 to $55m in 2020-25?

Non-network

23. Please expand on the increase in Investment in property, up from $49m to a proposed $108m (+17%)
24. Please clarify the spend in communications up, from $2m to $8m
25. With fleet, it was noted that – 'our fleet composition has increased steadily over recent years in line with the increased work programme and corresponding employee growth (Capex presentation 5 April 18 slide 62) – if so, now that the capital programme is largely stable, why $16m (17%) increase from current period to next? Note trend $109m (10-15), $92m (2015-20), $108m (2020-25). Productivity? Purchasing? ratios to # staff or value of work?
26. The property fact sheet 'Power Networks – Capital Expenditure: Property' discussed property investments in the 15-20 period, but did not discuss the property development plans for 2020-25.

27. Has there been any impact from the under expenditure in non-network investment this current period? Has work or expenditure that was planned (and funded) in 2015-20 been brought forward to 2020-25?
28. Fleet costs are noted as being cyclic. Could SAPN provide more insight into the fleet utilisation, ratios per staff, kilometres travelled? It would be useful to compare SAPN data with that of Essential Energy, Powercor and Ergon Energy.

A2.Pricing Directions: A Stakeholder Perspective

Objective of tariffs and related instruments

The objective is to develop a pricing strategy comprising tariffs and other supporting incentives and measures that:

- Promote more efficient, lower cost means of meeting consumers' demand for energy services
- Reflect consumers' preferences, such as enhancing customers' control over their bills and encourage tariff transparency and consumer agency/empowerment.

Many utilities have the aim of 'putting the customer at the centre', as successful competitive businesses do. These objectives support, and provide a test, for that objective.

Note: by supporting 'incentives and measures' we mean programs such as:

- locationally specific tariffs and payments to consumers and purchases of demand reduction from intermediaries, such as retailers or other energy service providers, that encourage reduction in peak loads at critical parts of the network
- alliances with retailers and other energy service providers to roll-out innovative end-user technologies that promote more flexible and efficient provision of energy services
- information programs and other 'nudges' designed to inform consumers and encourage consumers to manage loads in their and the network's interest.

Key features of the pricing strategy and TSS

Key features of a successful pricing strategy are that:

- it uses customer-facing language
- is adaptable to new information and changing technologies and demand patterns
- is adaptable to the different circumstances of each network
- is integrated with Demand Management strategy, programs, and incentives
- engages with the retailers and other energy service providers

Central to this is the understanding that consumers do not want electricity per se; they want the services that can be provided by using electricity: power (to produce things and for communication and entertainment), heating, and comfort.

Customer-facing language

The primary audiences for the TSS may well be the AER, retailers and energy service providers, and some large consumers. It may only be read by a small number of other consumers, but the objective should still be to express it in terms that the final consumer can understand. However even more important will be the clarity of the accompanying consumer information package (paper and electronic) that should communicate the tariffs, what the tariffs hope to achieve, and the opportunities for customers to reduce their cost of using the network in simple terms. For example, 'costs you can control' may be a better way of expressing 'variable charges'.

Adaptability

Circumstances can change significantly, quickly, and in directions not anticipated. For example, in the lead-up to the review of the pricing principles by the AEMC, peak demand had been rising quickly

putting pressure on existing networks and investment requirements. By the end of the AEMC review the problem was one of stagnant or declining demand and the implications of this for the fixed component of network bills. This is a practical example of changes occurring in a short term that can lead to significant differences in pricing strategies. It is expected that the pace of change in the technology for supply and use of energy to provide the services consumers need will accelerate. Our knowledge of how we can best provide the right signals to consumers is also expanding and changing. It is increasingly understood that it is not all about the price, but understanding what signal (price and non-price or informational) and how consumers respond to different signals. This is leading to innovations in customer-facing signals in various fields that are moving beyond traditional pricing models. While NSPs may innovate in pricing the responses of customers and retailers and other intermediaries may be uncertain. Hence, there may be a need to adapt strategies to their responses.

The key implications are that:

- the 'end-point' for pricing should not be seen as fixed. It is important to have a vision of where prices are headed, but this end-point cannot be fixed. IT will need to adapt to changing circumstances, new information, and responses of others.
- mid-point reviews of the TSS are desirable to build in adaptability in pricing strategies
- changing end-points may well mean that prices are in 'constant transition.

Network Specific

Different networks may face different problems that will result in different transition paths and end-points, especially in regard to the balance between fixed and controllable costs, the nature of the demand charge, and the choices between demand and capacity charges. There may be differences in the metering/technology infrastructure, particularly the roll-out of smart meters, that affect the feasible tariff options. Another key factor will be customer composition and demand growth. A network which has broadly-based growth in customers and demand may well move towards a broadly based tariff with a strong demand/capacity signal. Other networks may face stagnant or falling demand on average with only a few pockets of growth. This will lead to different choices and perhaps greater reliance on specific options (tariff and non-tariff) in those locations where growth is driving expected costs. Networks with a larger proportion of remote or difficult to serve customers may face greater risk of 'customer exit' from the grid. The key question here is whether the marginal costs of supplying those customers from the grid is greater than or less than the cost of self-supply. If it is, the network may try to design tariffs to discourage inefficient exit that would leave other customers having to pay more.

Role of Retailers

Except for some very large customers, the tariffs the customers see are the tariffs charged by the retailer which recover generation costs and the retailers own-costs as well as the network charges. At present customers mostly do not see the network charges directly and retail charges do not necessarily simply pass-on the network charges in the form and structure that they see them. The signals sent by networks may not only be 'washed out'; they may be substantially changed by the retailer. This is not necessarily a problem as long as the retailers see the cost reflective charges, bear the associated risks, and work with customers in whatever manner in response to the signals provided by the network charges. However, it is important that networks work with retailers and other service providers to ensure that:

1. there is a good understanding of the cost drivers the network is facing and points of current or potential congestion; and

2. opportunities to work together to maximise efficient use of distributed resources in areas of constraint are explored.

This may raise questions of the nature of the relationship between networks and retailers and other energy service providers and what forms of strategic alliances are acceptable where the network has no direct interest in retailing.

One option may be to require retailers to offer at least one pricing option that passes through the network tariffs as set by the DNSP.

Expectation for 'end point' of network pricing strategy and tariff design[23]

1. As peak demand is a more prominent cost driver for networks than energy consumption the objective is to signal these costs to retailers and customers in a way that customers can respond to and reduce future costs. Just and equitable demand or capacity-based tariffs are the most direct way of signalling these costs but a highly targeted volumetric rates may also achieve this objective. These tariffs would be the standard tariff. The demand or capacity component is equal to or greater than the LRMC averaged across the network.
    - Demand /capacity better signals cost drivers than volumetric charges
    - Consumers need to be aware of and be able to respond to peak demand signals

    The design and implementation of the tariff would have regard to the impacts on consumers.
2. Priority should be on the transition to demand/capacity tariffs. TOU tariffs today are highly averaged and hence poorly targeted on the key periods of high demand, and often have too little difference between the peak and off-peak rates to achieve the objectives. However, there may be a role for a volumetric tariff that is much more closely targeted on the key periods of high demand.
3. Under demand tariffs a key issue is what demand, what peak? Should it be the local or a broader, a coincident peak or the customer's peak demand? How often should peak demand be measured – a few nominated peak days or monthly or annual? There may not be a single 'correct' answer. It requires a balance between a relatively stable, easier to understand measure of demand and other measures of demand that can better measure the impact on future investment needs. Hence the choices made may depend on the importance of the demand signal in terms of the opportunities to defer investment, the nature of the customers and their capacity to respond, and whether it is the standard tariff or a more dynamic, locational-specific tariff. Decisions on the measurement of demand used should be supported by analysis at the sub-station level and may vary between DNSPs due to the differences in composition and location of customers. There may be areas with significantly different requirements – such as areas with high levels of tourism or specific activities like skiing. Optional locational tariffs may be the best means of responding to these circumstances, based on the outcome of research to reveal use profiles for each area.
4. Residual costs recovered by charges that are 'less distorting'[24] such as fixed charges but increases in fixed charges should be tempered by:

[23] As we understand it at this stage. New technologies, information and new thinking will see a continual evolution in ways we perhaps may not be able to envisage at present.

[24] It is likely that usage charges based on LRMC will not yield sufficient revenue to cover all the allowed costs of the NSP. If so, economic efficiency is enhanced if the remaining revenues are raised through charges that have as little impact on behaviour as possible.

- Recognition consumers prefer variable to fixed charges[25] – consumers want to do the right thing and be rewarded for it
- Consideration of consumer impacts
- Consideration of environmental costs in setting variable charges (i.e. in an energy charge or the demand or capacity charge)[26]. This supports the achievement of policy objectives of reducing carbon emissions; is consistent with NEO, which is an economic objective, and the economically efficient utilisation of network assets; and reduces the long term costs to consumers given the carbon reduction objectives. It also helps a) reconcile efficient tariffs with consumer preferences for greater control over the bill and to be rewarded for 'doing the right thing' as they see it and reducing usage b) reduce the impacts – and the often perceived inequity - of high fixed charges. Ongoing research provides the opportunity to test this perception.

5. The standard tariff is unlikely to be location specific (see point 3 above). It will be highly averaged but is aimed at encouraging some demand response consistent with overall objective
6. Application of the standard tariffs should be mandatory for new customers or connections where a new meter with different capabilities has been installed initially then expanding to all customers, recognising that this may impact on transitional arrangements and support. If mandatory application is not achievable in the short term, opt-out approaches should be adopted, but preferably not to a tariff with a single energy rate. Tariffs be set to tilt people towards not opting out, and supported by information programs and other incentives.
7. Innovative, dynamic local tariffs (eg critical peak rebates but all options should be 'on the table') aimed at reducing demand at/when it will make the biggest difference to capex requirements by promoting efficient distributed resources. These innovative tariffs are most likely to be optional and will require partnerships with retailers and energy service providers.
    - Where dynamic pricing is offered consumers may prefer rebate programs (with high 'normal' charges) than very large peak charges
8. Tariffs should not look beyond the meter
    - What customers pay in network charges should reflect their load profile not what energy-related equipment (e.g. Electric Vehicles s or PV panels) they have
    - But the networks/retailers/ESCOs may want to know what equipment consumers have so they can work with consumers to optimise my energy services.
9. As the economics of renewable energy continues to improve and renewable energy capacity increases, two-way flows will become a more important feature of the energy system and will introduce new challenges in pricing. To the extent that two-way flows have a different impact on network costs, this should be reflected in the pricing (including network support payments) for those flows. The objective should be to price access to the distribution networks in a manner that:
    - Provides signals for renewable capacity to locate in areas and be operated in a manner that benefits the network where possible
    - Fairly reflects the costs imposed on the distribution network as well as the benefits that it may provide.

[25] Fixed charges refer to per customer charges that do not vary with past or current demand or consumption. A capacity charge set based on demand in previous periods is not, under this definition, a fixed charge aven though within the year it may not vary from month-to-month.

[26]

10. At the retail level, or in partnership with retailers and ESCOs, innovative incentives and nudges – information programs, rebates rather than prices, special 'bonuses' etc may be more effective than standard incremental price changes. The learnings from behavioural economics on how people respond to signals can be important in developing tariff strategies.

Note: (1)-(5) sets up the standard tariff which will probably help a bit but the action/benefits are really in the locational specific pricing and incentives at (7).

Framing the Pricing Strategy

Scope of the pricing strategy

In considering the scope of the pricing strategy it is important to remember:

1. It is not just about traditional tariffs and structures
2. There must be an integration between pricing and incentives for demand management and distributed resources.
3. The strategy should reflect customer preferences.

The tariff structures in the TSS should not be a mechanical application of the LRMC pricing rule. Behavioural responses are not all about prices. Innovation in pricing and other instruments may well come from extensions of the learnings from behavioural economics into tariffs rather than econometric studies.

Demand management incentives that are likely to be location specific should be seen as an integral part of the tariff strategy. Locational signals that best reflect ex-ante costs may be provided by demand management incentives as well as, or instead of, standard tariffs. This may have implications for how networks approach and structure the development of tariffs and demand management incentives so that they are not developed in isolation. In assessing whether the tariff strategy meets the requirements of the network pricing principles the AER should asses the total tariff package including the demand management incentives.

Consultation by networks with their customers have highlighted that:

- Many customers have proactively sought to improve their energy efficiency
- They have done this not just to reduce their own bill but because they see it as doing the 'right thing' to benefit the environment
- Even though there is an element of 'green altruism' that consider that they should be able to benefit from reducing their consumption.

These preferences should be considered in determining the balance between fixed and variable costs and how sunk costs should be recovered.

What are the relevant costs?

Two issues in estimating the relevant costs are:

1. What is the cost basis - market costs (i.e. what the utilities pay) or economic costs (i.e. resource costs including environmental costs)? Principles of economic efficiency support inclusion of estimates of environmental costs where these are not priced into the market costs. To not do so will encourage overuse of resources with adverse consequences for the community.
2. What should be the basis of the estimation of LRMC. The principles allow for the use of either the Average Incremental Cost or Turvey (Perturbation) methods. The AIC approach is simpler,

is more widely used in the DNSPs, but is less time or location specific than the Turvey method. In contrast, the Turvey method can provide a stronger locational signal and is more sensitive to the timing of new investment requirements. Hence, while the AIC may be preferred in estimating variable rates for the standard tariffs, the Turvey method may be more appropriate for locational price signals.

Customer impacts

Where significant tariff changes are proposed the DNSP should provide well-founded, comprehensive modelling of the impact of the changes on various users (classified by tariff class, usage patterns, and socio-demographic characteristics). Best practice impact modelling would link consumption data to household socio-demographic data and undertake microsimulation modelling that examines impacts pre- and post- expected behavioural responses.