SA Power Networks

Attachment 6

Operating expenditure

2020-25 Regulatory Proposal

31 January 2019

This section outlines:

- how we developed our operating expenditure forecast using the ‘base-step-trend’ methodology; and
- how we have incorporated customer and stakeholder feedback into our forecast.

Company information

SA Power Networks is the registered Distribution Network Service Provider (**DNSP**) for South Australia. For information about SA Power Networks visit www.sapowernetworks.com.au

Contact

For enquiries about this Revenue Proposal please contact:
Richard Sibly
Head of Regulation
SA Power Networks
GPO Box 77
Adelaide SA 5001
sapn2020proposal@sapowernetworks.com.au

Disclaimer

This document forms part of SA Power Networks' Regulatory Proposal (**the Proposal**) to the Australian Energy Regulator (**AER**) for the 1 July 2020 to 30 June 2025 regulatory control period (2020-25 **RCP**). The Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgment.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Proposal includes documents and data that are part of SA Power Networks' normal business processes, and are therefore subject to ongoing change and development.

Whilst care was taken in the preparation of the information in this Regulatory Proposal, and it is provided in good faith, SA Power Networks, its officers and shareholders accept no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it for a different purpose or in a different context.

Copyright

Note

This attachment forms part of our Proposal for the 2020-25 RCP. It should be read in conjunction with the other parts of the Proposal.

Our Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 18:

Document	Description
	Regulatory Proposal overview
	Customer and stakeholder engagement report
! űűl·ŏKϓŜyű м	! yÿdzl·ƭ ǁŜøŜydzŜ ǁŜljdzʎǁŜϓŜyű l·yŘ ŏƻyűǁƻƭ ϓŜŏKl·yʎăϓ
! űűl·ŏKϓŜyű н	wŜƺdzƪl·űƻǁè l·ăăŜű ōl·ăŜ
! űűl·ŏKϓŜyű о	wl·űŜ ƻƒ wŜűdzǁy
! űűl·ŏKϓŜyű п	wŜƺdzƪl·űƻǁè ŘŜLJǁŜŏʎl·űʎƻy
! űűl·ŏKϓŜyű р	/ l·LJʎűl·ƭ ŜÈLJŜyŘʎűdzǁŜ
! űűl·ŏKϓŜyű c	**hLJŜǁl·űʎyƺ ŜÈLJŜyŘʎűdzǁŜ**
! űűl·ŏKϓŜyű т	/ ƻǁLJƻǁl·űŜ ʎyŏƻϓŜ űl·È
Attachment 8	Efficiency benefit sharing scheme
Attachment 9	Capital expenditure sharing scheme
Attachment 10	Service target performance incentive scheme
Attachment 11	Demand management incentives and allowance
Attachment 12	Classification of services
Attachment 13	Pass through events
Attachment 14	Alternative Control Services
Attachment 15	Negotiated services framework and criteria
Attachment 16	Connection policy
Attachment 17	Tariff Structure Statement
Attachment 18	List of Proposal documentation

Contents

List of figures

List of tables

6 Operating Expenditure

6.1 Overview

Our operating expenditure (**opex**) forecast for the 2020-25 regulatory control period (**RCP**) has been developed in accordance with clause 6.5.6 of the National Electricity Rules (**NER**). It reflects the efficient and prudent costs of SA Power Networks achieving the opex objectives[1] and a realistic expectation of the demand forecast, and cost inputs required to achieve those objectives.[2]

Our regulatory proposal for the 2020-25 RCP (**Proposal**), and consequently our opex forecast, has been informed by an extensive and rigorous customer engagement program. Throughout our engagement program, our customers and stakeholders have consistently told us that they value three key things, namely:

- keeping prices down;
- maintaining a safe and reliable network; and
- prudently transitioning to a new energy future.

Our customers have also told us that they support achieving an appropriate balance between these key objectives.

Our Proposal recognises that the electricity industry is being transformed by customer choices and technology and we need to achieve an appropriate and transparent balance between these key objectives when managing this transformation. We will do this by combining our experiences and perspective with the views of our customers and stakeholders.

In developing our opex forecast for the 2020-25 RCP, we have (amongst other things):

- reflected what is important to customers and stakeholders, gained through our early engagement commencing in 2017;
- considered direct feedback from customers and stakeholders concerning the preliminary plans that we shared during the 'deep dive/information' workshops conducted in 2018 as part of our customer engagement process;
- published our 2020-2025 Draft Plan in August 2018 and considered the feedback received from customers and stakeholders concerning that Draft Plan;
- considered our historical and current performance;
- identified regulatory and environmental factors in the 2020-25 RCP that will require changes to the current opex level; and
- applied the Australian Energy Regulator's (**AER's**) base-step-trend methodology and other requirements of the AER's Expenditure Forecast Assessment Guideline (**EFAG**).

Our forecast opex for the 2020-25 RCP is **$1,530** million ($June 2020, excluding debt raising costs). This opex is required in order to achieve each of the opex objectives, while also recognising that affordability is a key concern for our customers and stakeholders.

[1] *NER 6.5.6(a).*
[2] *NER 6.5.6(c).*

Table 6-1: SA Power Networks opex forecast for the 2020-25 RCP

Expenditure category (June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Base Year	279.8	279.8	279.8	279.8	279.8	**1,399.0**
Step changes	14.3	14.3	15.3	15.5	15.8	**75.1**
Output Growth	2.4	4.5	6.2	7.9	9.6	**30.6**
Real Price Growth	1.3	3.1	5.2	7.2	8.9	**25.7**
Productivity Adjustment	-	-	-	-	-	**-**
Opex excluding debt raising	**297.9**	**301.7**	**306.5**	**310.3**	**314.0**	**1530.4**
Debt raising costs[3]	4.0	4.1	4.1	4.1	4.1	**20.5**
Total opex*	**301.9**	**305.8**	**310.6**	**314.5**	**318.1**	**1551.0**

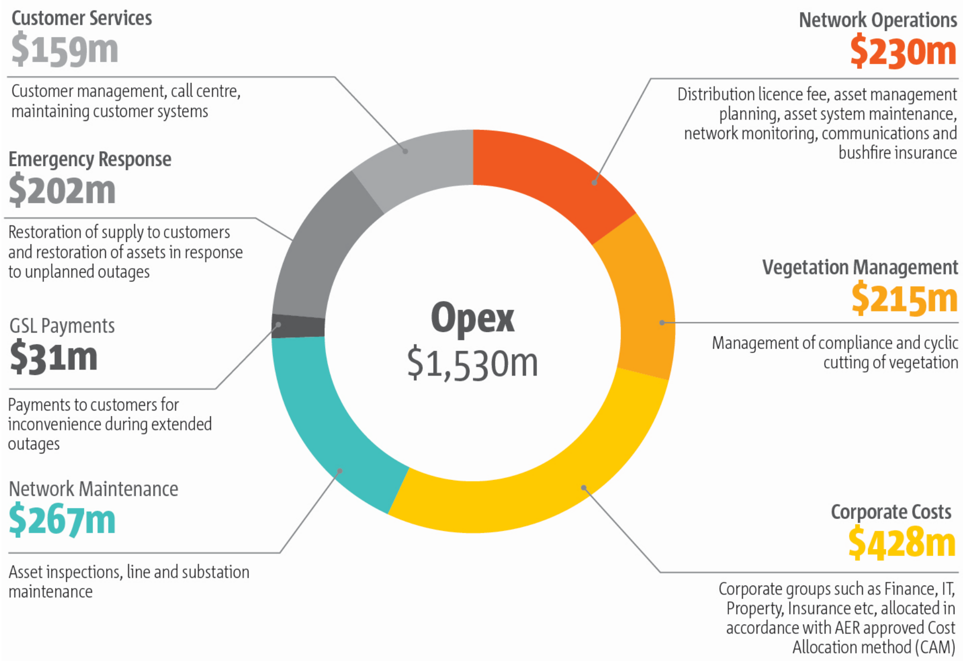
**totals may not add up due to rounding*

Our forecast opex comprises money spent on maintaining and operating the assets that make up and support our distribution system and include costs associated with:

- operating the network, including network monitoring and asset management;
- maintaining powerlines and substations to enable a safe and reliable distribution system;
- managing vegetation around powerlines to mitigate bushfire risk and maintain safety and reliability;
- restoring supply for unplanned power outages caused by weather events, equipment failure or third party damage;
- Guaranteed Service Level (**GSL**) inconvenience payments to customers when outages exceed the levels of service prescribed in the Essential Services Commission of South Australia (**ESCoSA**) Service Standard Framework;
- customer service costs; and
- business support costs, including costs for corporate groups such as information technology, property management and financial services.

Figure 6-1 contains a summary of the opex components and their cost forecasts for the 2020-25 RCP.

Figure 6-1: Forecast opex for the 2020-25 RCP by category ($June 2020)



[3] Our opex forecast referred to in this Attachment excludes debt raising costs which are dealt with in 'Attachment 3 - Rate of Return and financing costs' and are not forecast using the base-step-trend approach.

6.2 Rule requirements

Clause 6.5.6(a) of the NER provides that SA Power Networks must submit a building block proposal for the 2020-25 RCP that includes a forecast of the opex it requires in order to achieve each of the following opex objectives:

- meet or manage the expected demand for standard control services (**SCS**) over the 2020-2025 RCP;
- comply with all applicable regulatory obligations or requirements associated with the provision of SCS;
- maintain the quality, reliability and security of supply of SCS (where there are no applicable regulatory obligation or requirement);
- maintain the reliability and security of the distribution system through the supply of SCS (where there are no applicable regulatory obligation or requirement); and
- maintain the safety of the distribution system through the supply of SCS.

Clause 6.5.6(c) of the NER provides that the AER must accept the proposed opex forecast that SA Power Networks includes in its building block proposal if the AER is satisfied that the forecast opex reasonably reflects each of the following opex criteria:

- the efficient costs of achieving the opex objectives;
- the costs that a prudent operator would require to achieve the opex objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

Further, clause 6.5.6(e) of the NER requires that, in deciding whether or not it is satisfied that the total of our forecast opex reasonably reflects the opex criteria, the AER must have regard to the following opex factors:

- the most recent annual benchmarking report that has been published under clause 6.27 of the NER and the benchmark opex that would be incurred by an efficient distribution network service provider (**DNSP**) over the 2020-2025 RCP;
- our actual and expected opex during any preceding RCPs;
- the extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by SA Power Networks in the course of our engagement with electricity consumers;
- the relative prices of operating and capital inputs;
- the substitution possibilities between opex and capital expenditure (**capex**);
- whether the opex forecast is consistent with any incentive scheme or schemes that apply to SA Power Networks under clauses 6.5.8 or 6.6.2 to 6.6.4 of the NER;
- the extent the opex forecast is referable to arrangements with a person other than SA Power Networks that, in the opinion of the AER, do not reflect arm's length terms;
- whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b) of the NER;
- the extent we have considered, and made provision for, efficient and prudent non-network alternatives;
- any relevant final project assessment report (as defined in clause 5.10.2 of the NER) published under clause 5.17.4(o), (p) or (s) of the NER; and
- any other factor the AER considers relevant and which the AER has notified to SA Power Networks in writing, prior to submission of our revised regulatory proposal for the 2020-25 RCP (**Revised Proposal**) under clause 6.10.3 of the NER, is an opex factor.

SA Power Networks is of the view that its proposed opex forecast meets the opex objectives and opex criteria, taking into account the opex factors and therefore should be accepted by the AER as part of its distribution determination for the 2020-25 RCP.
In addition, our proposed opex forecast reflects a balanced approach that:

- achieves the national electricity objective (**NEO**) to promote efficient investment in, and efficient operation of use of, our electricity services for the long-term interests of our customers with respect to price, quality, safety, reliability and security;[4] and
- meets the revenue and pricing principles by providing us with a reasonable opportunity to recover at least the efficient costs we incur in providing direct control services and complying with our regulatory obligations or requirements.[5]

[4] *National Electricity Law, section 7.*
[5] *National Electricity Law, section 7A.*

6.3 Customer and stakeholder feedback

Our customer engagement program sought to understand the expectations, priorities and concerns of our customers and stakeholders, so we could make sure that our forecast expenditure for the 2020-25 RCP is in their long-term interests and otherwise promotes the achievement of the NEO.

Constructive feedback received throughout our engagement program has assisted with the development of our Proposal. Specific feedback received on our opex forecast has been considered and incorporated into this Attachment. The feedback arising from the engagement program has been rich and detailed, and Table 6-2 below provides an overview of the key points raised during our engagement program relating to our opex forecast.

Table 6-2: Summary of feedback on SA Power Networks customer engagement on forecast opex

What we heard	Our Response	Evidence
Productivity Customers and stakeholders sought a productivity adjustment to be applied.	Productivity growth of 0.0% has been included in our opex forecast. (discussed further in section 6.7.3.3 below)	We have incorporated productivity growth of 0.0% for the reasons set out in our submission to the AER's separate review and consultation process on productivity, which is currently ongoing.
Real price labour escalations Customers queried how a real labour increase aligns with the low wages growth in South Australia.	Our forecast opex adopts the methodology applied by the AER in forecasting real price growth (discussed further in section 6.7.3.2 below).	The labour escalations that we have applied are independently forecast by economic consultants to represent real wage increases expected to apply to businesses in the utilities industry sector in South Australia in the 2020-25 RCP.
Step Changes More information was sought by customers and stakeholders on the costs and benefits of proposed step changes.	We have reviewed all proposed step changes for their alignment with the opex criteria requirements. We have removed some earlier contemplated step changes, reduced the cost of other step changes and added a new step change covering a change to our treatment of expenditure on cable and conductor minor repairs. Detailed information is provided in section 6.7.2 below.	We have provided business cases, outlining our cost benefit and options analysis for each proposed step change.
Continue to find efficiencies Customer and stakeholders want confidence that we will continue to find more efficient ways to deliver our work to keep opex down into the future.	Through our deep dive workshop, ongoing engagement with our Customer Consultative Panel, and the development of our Efficiency Fact Sheet, we provided detailed information about the new processes and technologies we have been using to minimise our opex. The current regulatory framework is designed to provide incentives to achieve these goals on an ongoing basis.	AER benchmarking results demonstrate that SA Power Networks is one of the most efficient DNSPs across all opex categories. Detailed information is provided in section 6.6 below.

"SA Power Networks has demonstrated good performance in maintaining an efficient network…we are looking to see productivity measures introduced to help share their productivity savings with consumers"
Energy Consumers Australia

"Projected labour costs are higher than for businesses generally in SA and not consistent with a low wage growth environment"
SA Power Networks Customer Consultative Panel

"We consider there are opportunities to progressively pursue efficiency in both operating and capital expenditure and encourage SA Power Networks to address their future efficiency programs in the upcoming regulatory proposal"
Energy Consumers Australia

"In other areas of high costs and proposed step changes there may be opportunities to reduce expenditure, but it may also be that the expense can be justified in terms of additional benefits to consumers"
SA Power Networks Customer Consultative Panel

6.4 Revisions to opex forecast from our 2020-2025 Draft Plan

We released our 2020-2025 Draft Plan in August 2018 for consultation with our customers and stakeholders. The feedback that we received on our Draft Plan has helped shape and refine our proposed opex forecast for the 2020-25 RCP.

Our opex forecast has increased by $62.0 million ($June 2020) as compared to the opex forecast included in our 2020-2025 Draft Plan.

This has been mainly driven by a proposed change to our treatment of expenditure on cable and conductor minor repairs (ie an efficient capex/opex trade off or substitution) that better reflects the nature of this type of expenditure and addresses potential intergenerational inequities that could be caused by continuing to classify this type of expenditure as capex. In other words, the majority of this increase in forecast opex is off-set by a corresponding decrease in our forecast capex resulting in a cost/benefit neutral outcome as explained in section 6.7.2.4.

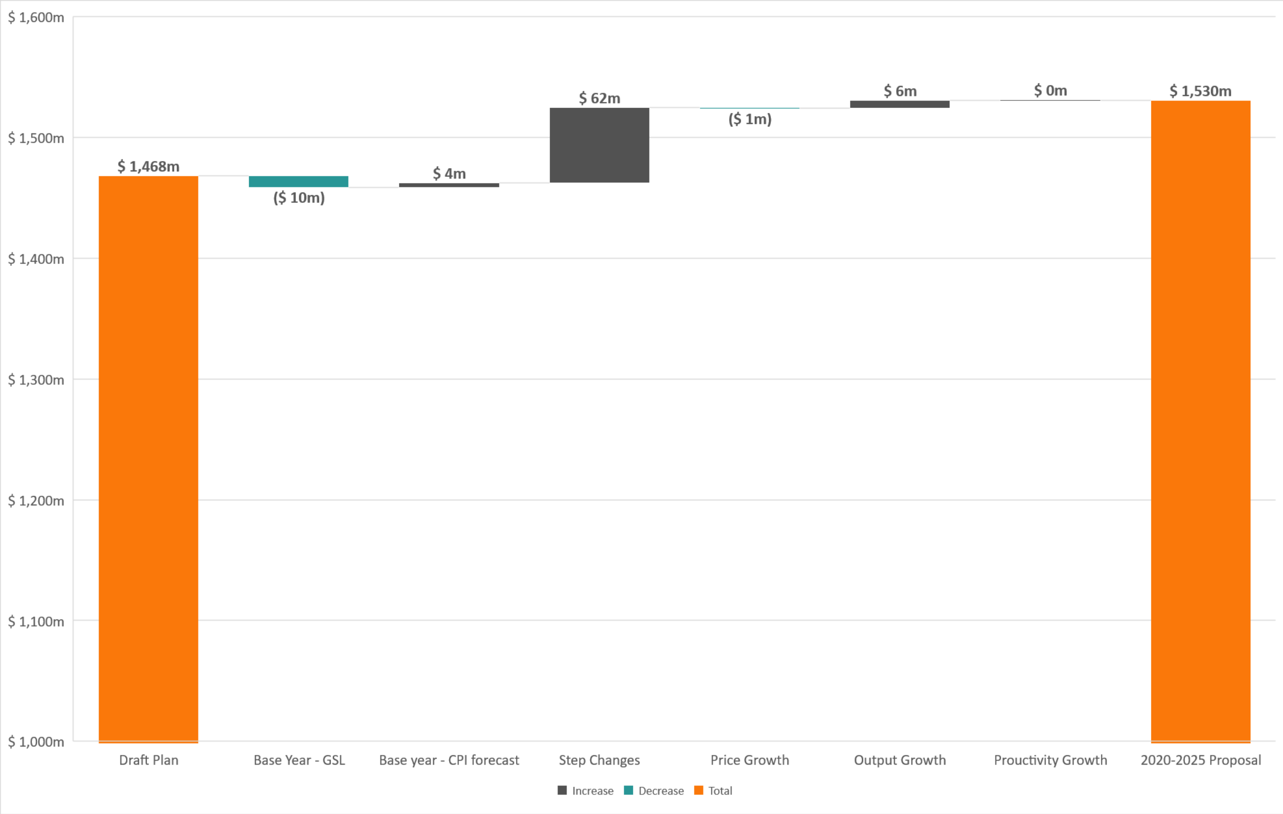
The balance of the increase is driven by market factors such as increases in the Consumer Price Index (**CPI**) forecast and revised customer growth estimates. Refinement of early forecasts, feedback received from customer and stakeholders and discussions with AER staff, have partially offset these increases. Detailed explanations on the build-up of the individual components of the opex forecast are included in section 6.7 Opex forecast.

The movements from our 2020-2025 Draft Plan (as depicted in Figure 6-2 below), were driven by the following factors:

- **GSL changes** - In consultation with AER staff we have revised our estimated expenditure in the 2018/19 base year to reflect average GSL expenditure over a five-year period from 2013/14 to 2017/18.
- **CPI** – CPI forecast has been updated to reflect the revised December 2018 forecast of 2.00% by the Reserve Bank of Australia (**RBA**), which has impacted the escalation of our base year opex forecast.
- **Step changes** – Step changes have increased by $62.4 million ($June 2020) as follows:
  - we have proposed a new step change covering a change to our treatment of expenditure on cable and conductor minor repairs, whereby this type of expenditure will be treated as opex rather than capex (ie an efficient capex/opex trade-off or substitution);
  - our proposed step change for the billing system replacement has been removed (in addition to the customer engagement technologies step change that was removed prior to issuing the 2020-2025 Draft Plan) based on customer feedback from our earlier workshops;
  - we have reduced our low voltage (**LV**) management step change; and
  - we have refined the cost forecasts of all other remaining proposed step changes.
- **Price growth** – Price growth (labour escalation) has been updated by BIS Oxford Economics with Australian Bureau of Statistics (**ABS**) data for year ending 30 June 2018.
- **Output growth** – The output growth methodology has been updated to reflect:
  - the weighted average of the two Cobb Douglas econometric models used in the AER's annual benchmarking; and
  - our finalised customer number growth forecast for 2020-25 RCP.[6]

[6] Customer number growth forecasts for the 2020-25 RCP are discussed in detail in Attachment 17 – Tariff Structure Statement.

Figure 6-2: Movement in opex forecast to 2020-2025 Draft Plan ($June 2020)



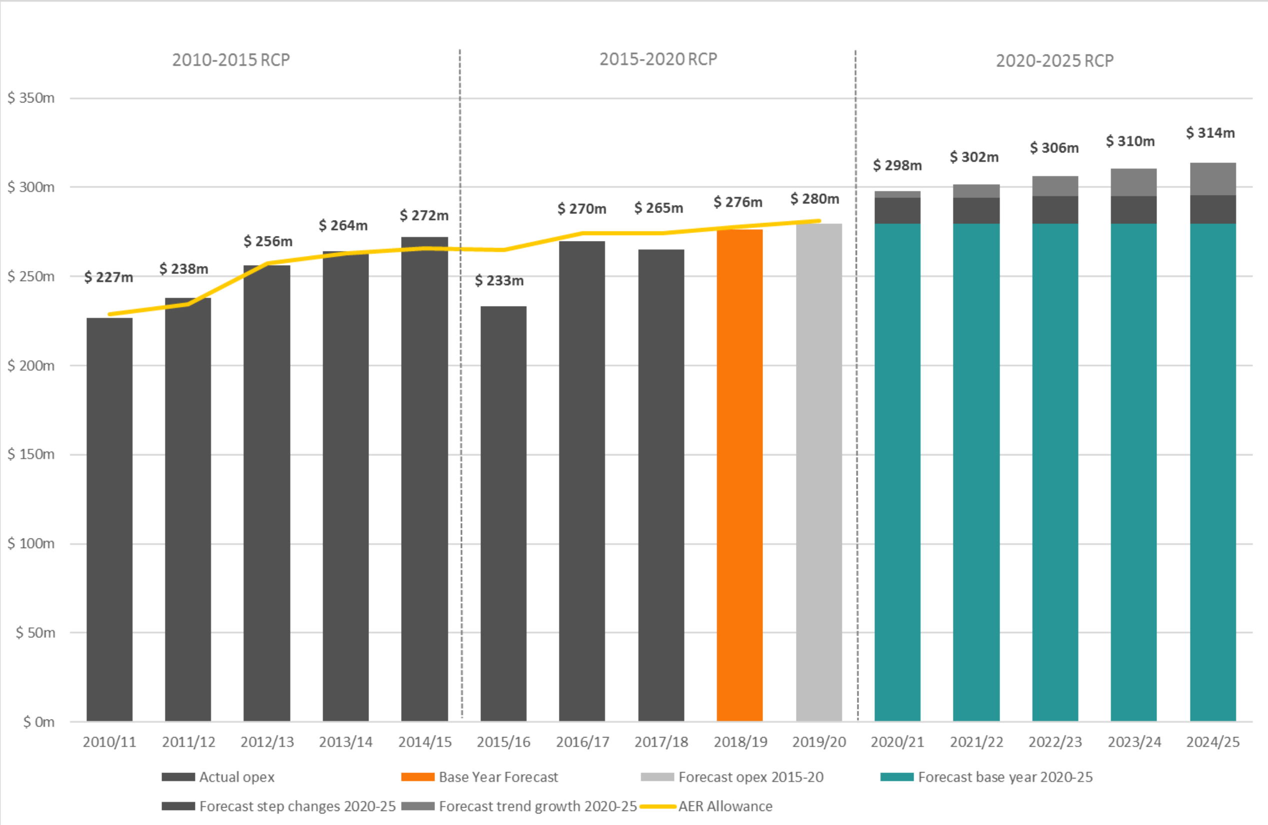
6.5 Historical Performance

In accordance with clause 6.5.6(e)(5) of the NER, our opex forecast for the 2020-25 RCP has been prepared with regard to the actual and expected opex for the 2010-15 RCP and the 2015-20 RCP. Operating costs generally recur each regulatory year, but some programs are cyclical. For example, vegetation is cleared around powerlines over a three-year cycle in non-bushfire risk areas. Additionally, costs may fluctuate from year to year because of severe weather events, which can directly affect emergency response costs and GSL inconvenience payments. New regulatory obligations have also been imposed since the 2015 Determination and the costs of complying with these new regulatory obligations were not included within the opex allowance approved by the AER for the 2015-20 RCP (including, for example, ring-fencing, metering contestability, reporting and auditing obligations).

We have considered our historical performance at both the total and category level in the build-up of our opex forecast for the 2020-25 RCP. This information was shared with our customer and stakeholder groups throughout our customer engagement program and their feedback has been used to help build our opex forecast for the 2020-25 RCP.

6.5.1 Comparison of total historical and forecast opex

Figure 6-3: SA Power Networks historical and forecast opex ($June 2020)



Opex for the 2010-15 RCP was largely in line with our approved opex allowance. The opex escalated over the 2010-15 RCP due to external factors, such as:

- the breaking of the 'millennium drought' in South Australia in 2010 which led to substantially more vegetation growth and increased the volume of work required under our vegetation management program to meet our regulatory obligations;
- an unprecedented take-up of solar system installations, largely driven by the State Government Feed-In Tariff scheme, significantly increased our administrative costs. It also increased the costs

associated with investigating, managing and maintaining voltage levels within specified standards;[7] and
- the volume and severity of extreme weather events increased, leading to higher emergency response costs and GSL inconvenience payments.

In the 2015-20 RCP, our opex is forecast to be lower than our allowance in each regulatory year. The benefit of this reduction in opex will be passed on to customers as lower base year costs in the 2020-25 RCP. The factors having the greatest impact on our opex in the 2015-20 RCP include:

- The 2015/16 regulatory year did not reflect a normal regulatory year, with abnormally low expenditure resulting from several factors. For example, we reprioritised our work programs and delayed some work programs while the uncertainty concerning our revenue allowance for the 2015-20 RCP was being resolved.[8] Vegetation management expenditure was also lower due to the timing of the cutting cycle and there was a low incidence of extreme weather events.
- The 2016/17 regulatory year experienced extreme weather events at a record high, with nine Major Event Days (**MEDs**)[9] recorded (compared to a historical average of three to four per year), which meant increasing costs to repair and reinstate the network. Additionally, more than $25 million in GSL inconvenience payments were made to customers whose supply was interrupted because of weather-related system outages.
- The 2017/18 regulatory year again had a low incidence of extreme weather days. No MEDs were recorded during the regulatory year, resulting in lower emergency response costs and GSL inconvenience payments. However, vegetation management costs were higher than the previous two regulatory years due to the timing of the cutting cycle and because of above average rainfalls in the previous 2016/17 regulatory year.

6.5.2 Categories of opex

Our assessment of forecast opex has been undertaken on a total forecast opex basis consistent with the AER's preferred base-step-trend methodology as outlined in the EFAG. Although forecast opex is assessed as a total forecast, the EFAG notes that to enable assessment of base year expenditure, different techniques will be applied. These techniques may include the assessment of expenditure split by each opex and maintenance category.[10] This information is provided annually in response to the AER Regulatory Information Notices (**RINs**) which are used to benchmark our performance against other DNSPs. A summary of our categories of opex and the major drivers of operating costs is shown in Table 6.6.

Throughout our customer engagement process, we received requests for more bottom-up analysis of opex. For our customer and stakeholder workshop we provided internally generated benchmarking information based on RIN data. For the first time the AER has included similar information in its 2018 Annual Benchmarking Report (**2018 Report**). In most cases, SA Power Networks is shown to be among the most efficient DNSPs for each opex category. This is discussed further in section 6.6 Benchmarking.

SA Power Networks' Customer Consultative Panel (**SAPN CCP**) commented on our opex categories in its submission to our 2020-2025 Draft Plan. [11] Concerns were raised by customers and stakeholders that some opex categories appeared to be higher than necessary. In particular, some customers commented that our corporate costs (being 26% of total opex) and our customer service costs seemed high.[12] Aside from these

[7] The export of electricity into the LV network at low load times can result in higher voltage levels which are outside the standard.
[8] The AER's Final determination was not published until 29 October 2015.
[9] MEDs are defined by the AER as extreme weather or events that interrupt power to a significant number of customers for extended periods.
[10] *AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2017, page 28.*
[11] *SA Power Networks Customer Consultative Panel, Submission – SA Power Networks Draft Plan 2020-25, October 2018, page 22.*
[12] Unlike many of the other DNSPs we do not capitalise any of our corporate costs, therefore these costs do represent a larger portion of our opex as compared to other DNSPs. This is discussed further in section 6.6.2 Operating environmental factors.

comments, the SAPN CCP also noted that we have achieved significant improvements in all areas of vegetation management through collaboration with a dedicated reference group.[13]

In forecasting opex, we not only considered our total opex, but also our opex on a category basis. In accordance with clause S6.1.2(7) of the NER, Figure 6-4 below, provides a breakdown of our historical opex by category. For most categories, the opex year on year is relatively constant, which aligns with applying the base-step-trend methodology. The exceptions are the volatility and impact of MED extreme weather on GSL inconvenience payments and emergency response expenditure, and the cyclicality of our vegetation management program. Following discussions with the AER, an agreed approach to forecasting GSL expenditure has been reached. This approach is discussed in section 6.7.1.

Figure 6-4: SA Power Networks historical and forecast opex by category ($June 2020)

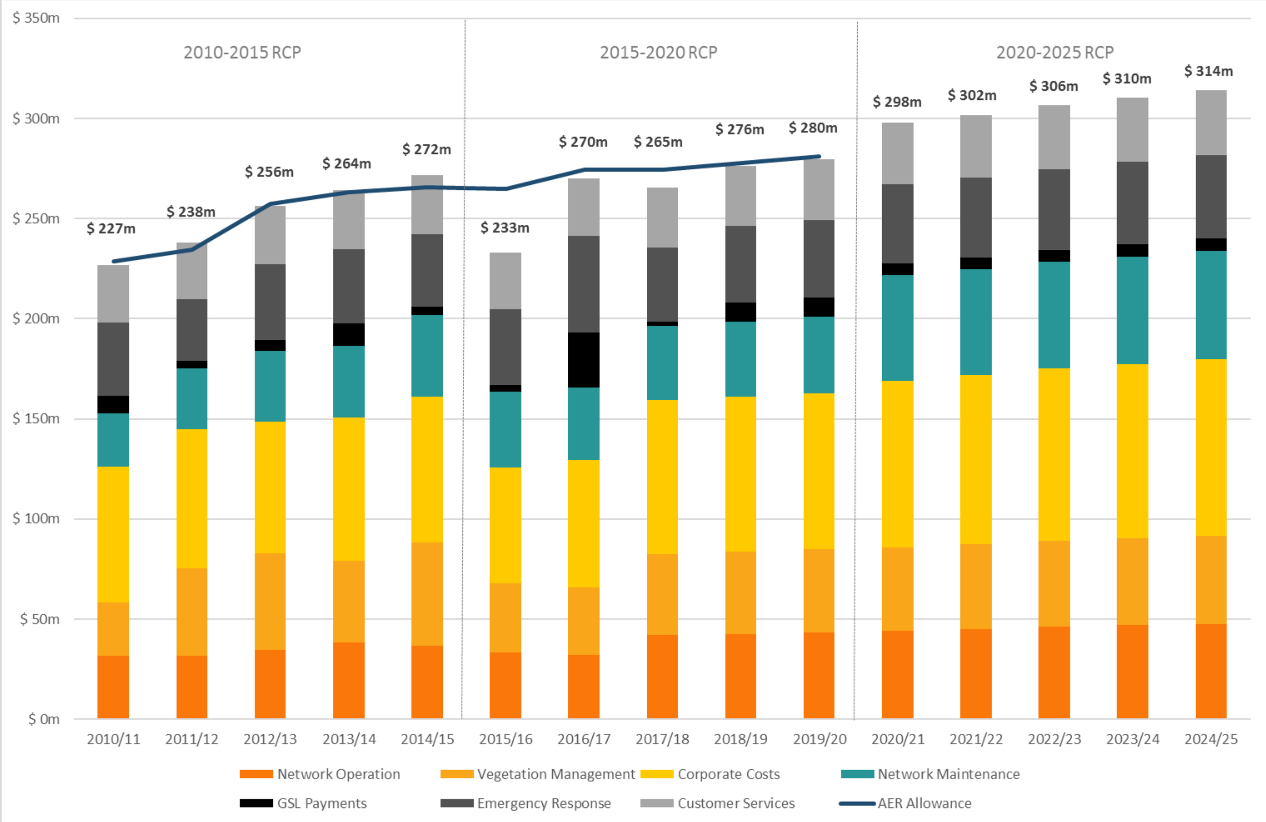


Figure 6-5: SA Power Networks opex expenditure categories

Network Maintenance	Asset inspection, line and substation maintenance
Vegetation Maintenance	Management of compliance and cyclic cutting of vegetation
Emergency Response	Restoration of supply to customers and restoration of assets in response to unplanned outages
GSL Payments	Payments to customers for inconvenience during extended outages
Customer Services	Customer management, call centre and maintaining customer systems
Network Operation	Distribution licence fee, asset management planning asset system maintenance, network monitoring, communications and bushfire insurance
Corporate Costs	Corporate groups such as Finance, IT, Property, Insurance etc. allocated in accordance with our approved Cost Allocation Method (CAM)

[13] *SA Power Networks Customer Consultative Panel, Submission – SA Power Networks Draft Plan 2020-25, October 2018, page 22.*

6.6 Benchmarking

In its final Framework and Approach paper for SA Power Networks for the 2020-25 RCP, the AER states that it will "take a base-step-trend approach to assessing forecast expenditure and in this context use top down economic benchmarking tools to determine the reasonableness of the forecast rather than a bottom-up assessment approach."[14] The AER acknowledges however that it may use any analytical tool at its disposal.[15] If our actual expenditure in our base year reasonably reflects the opex criteria, the AER will set our base opex equal to actual expenditure for that year using the revealed cost approach.[16]

In our view, a revealed cost approach to assessing the reasonableness of our opex forecast and in particular the efficiency of our proposed opex base year remains appropriate, noting that:

- the benchmarking outcomes reported by the AER in its annual benchmarking reports demonstrate SA Power Networks is one of the most efficient DNSPs in the National Electricity Market (**NEM**) having regard to a range of total opex and opex category specific measures; and

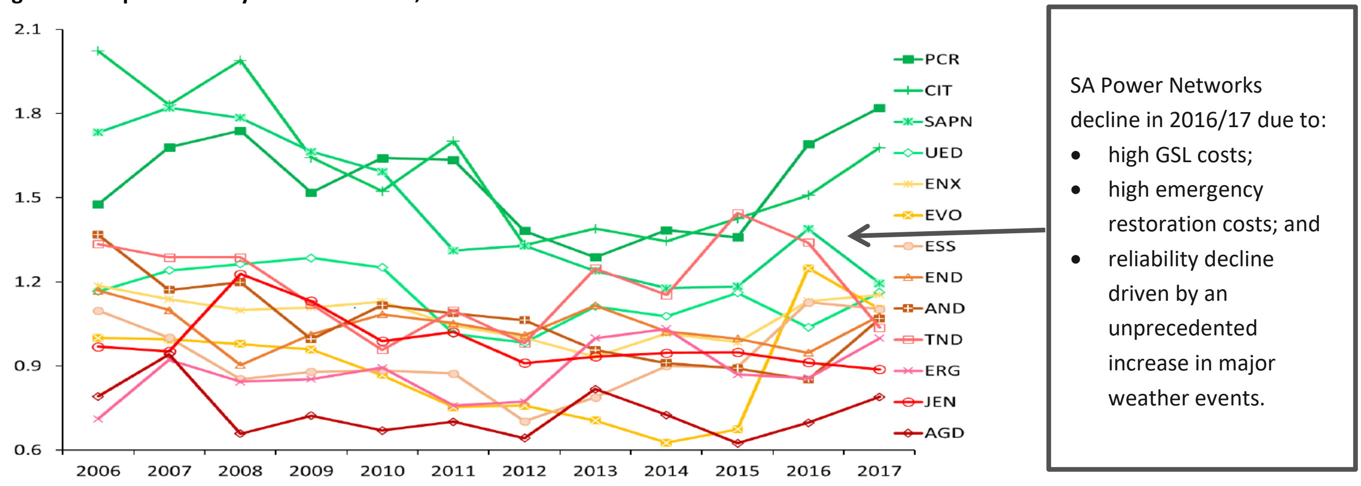
- these efficient benchmarking outcomes for SA Power Networks would be shown to be even more comparatively efficient if the AER better accounted for specific Operating Environment Factors (**OEFs**) which drive our opex spends.

6.6.1 Historical benchmarking

Historical benchmarking of SA Power Networks' performance in the AER's annual benchmarking reports has shown that we are consistently in the top quartile of all DNSPs on almost all measures.

On a state-wide multi-lateral total factor productivity (**MTFP**) basis, SA Power Networks, as the sole DNSP in South Australia, benchmarks as having the highest distribution productivity level over the 2006-2017 period.[17] On an individual DNSP basis, we rank second behind CitiPower,[18] which has the relatively small footprint of the Melbourne central business district. For opex multi-lateral partial factor productivity (**MPFP**) we rank third as shown in Figure 6-6 below.

Figure 6-6: Opex MPFP by individual DNSP, 2006-17[19]



[14] *AER, Final framework and approach SA Power Networks Regulatory control period commencing 1 July 2020, July 2018, page 78.*
[15] *Ibid, page 79.*
[16] *AER, Expenditure Forecasting Assessment Guideline for Electricity Distribution, November 2013, page 22.*
[17] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, page 12.*
[18] *Ibid, page 13.*
[19] *Ibid, page 16.*

SA Power Networks' inputs grew at a greater rate than outputs over the 2007-2014 period. This was largely due to increases in opex arising from changes in external factors such as the breaking of the millennium drought, the high take-up and installation of solar systems and an increase in severe weather events as described in section 6.5.1 above.

Our benchmarking outcomes had stabilised and showed improvement for the two years to 2016, before an unprecedented number of severe weather events in the 2016/17 regulatory year increased GSL payments, emergency response costs and reduced reliability. This resulted in a decline in our MTFP and opex MPFP benchmarking results in that regulatory year.

6.6.2 Operating environmental factors

The 2018 Report recognises that the AER's performance measurement is only indicative of a DNSPs relative performance as unique OEFs may affect a DNSP's costs and benchmarking performance.[20] This is relevant where opex may be higher relative to other DNSPs due to factors that are not driven by efficiency, and may therefore distort its relative benchmarking performance.

The 2018 Report includes commentary from independent consultants Sapere Research Group and Merz Consulting on the extent to which differences in measured performance may be affected by exogenous factors outside the control of each business.[21] However this commentary omitted some OEFs that significantly impact SA Power Networks.

For SA Power Networks, our most material and unique OEFs include our overhead capitalisation policy and the operation of our jurisdictional GSL scheme.[22] Historically, we have expensed all our corporate overheads and capitalised only a low percentage of network overheads, unlike many other DNSPs. On average, DNSPs have capitalised around 30% of corporate overheads and 40% of network overheads.[23] Had SA Power Networks adopted a similar capitalisation policy to other DNSPs, our opex would be lower by up to $40 million per annum (or 15%, with the balance of the costs otherwise included in our regulatory asset base (**RAB**)). We estimate that this would improve our MTFP by around 6% and opex MPFP benchmarking results by around 18%.

Consideration of differing capitalisation policies was excluded from the AER's consultant's brief, as it is not an exogenous factor. However, it is a factor that significantly impacts comparative benchmarking results and is not driven by efficiency. We elaborate further on capitalisation of overheads in section 6.6.3 below. In its 2018 Report, the AER has recognised that capitalisation is an important issue that it will consider as part of its ongoing development program.[24] It is also relevant to other aspects of the regulatory framework, such as the corporate tax allowance as discussed in Attachment 7 –Corporate income tax.

Historically, South Australia's jurisdictional GSL scheme has been more onerous and costly than those applying in other jurisdictions. In contrast to other jurisdictional schemes, our current GSL scheme is uncapped, both in terms of total payments across all customers, and payments to individual customers, and has multiple thresholds with increasing payments for longer duration outages. SA Power Networks' individual payments can be up to $605 per customer, while it can be as low as $80 in other jurisdictions. Additionally, we are required to provide payments to all impacted customers, whilst elsewhere it is the customer's responsibility to apply for payments. As well as the obvious impact on GSL inconvenience payments, administration of the scheme is also much costlier as a result.

[20] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, page 15.*

[21] *Ibid, page 23*.

[22] *The GSL scheme currently applicable to SA Power Networks is contained in the following document: ESCoSA, Electricity Distribution Code, version EDC/12, July 2015, clause 2.3.*

[23] *Data source: Category Analysis RINs, Expenditure Summary template. SA Power Networks' opex has been estimated had we capitalised overheads at an equivalent average of all DNSPs.*

[24] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, page vii.*

Further, the SA Power Networks GSL scheme requires payments on MEDs (ie major storm type events), unlike some other jurisdictions. In the 2016/17 regulatory year, due to an unprecedented number of severe weather events, we incurred GSL costs of more than $25 million, or 10% of our total opex.

SA Power Networks' jurisdictional GSL scheme will change from the 2020/21 regulatory year with individual duration payments replaced by total annual duration payments, and frequency payments simplified to one level of payment (refer to negative step change discussed in section 6.7.2.6 below). GSL payments will continue to apply on MEDs however.

Our 2016/17 opex demonstrates the materiality of the historical, jurisdiction specific, GSL inconvenience payments on benchmarking outcomes. The AER's OEF consultants have recognised that differences in the obligations and value of payments under GSL schemes in different jurisdictions may be material and require further examination.[25]

When the above OEFs are taken into consideration, our opex MPFP benchmarking results would be more favourable than what has been reported (by up to 30% in 2016/17).[26]

6.6.3 Category specific benchmarking

For the first time the AER has included category level partial performance indicators (**PPIs**) in its 2018 Report.[27] The AER has previously used category level PPIs as a supporting benchmarking technique in its distribution determinations to assess opex efficiency, with data extracted from DNSPs' RIN submissions. The category specific PPIs included in the 2018 Report are:

- vegetation management opex;
- maintenance opex;
- emergency response opex; and
- total overheads.

For all but the emergency response category, the costs for which are largely driven by uncontrollable major weather events, SA Power Networks is shown to be one of the lowest cost DNSPs over the 2013-17 period, as set out in Figures 5.6 to 5.9 below, extracted from the 2018 Report:[28]

Figure 5.6 Vegetation management opex per km of route line length ($2017)

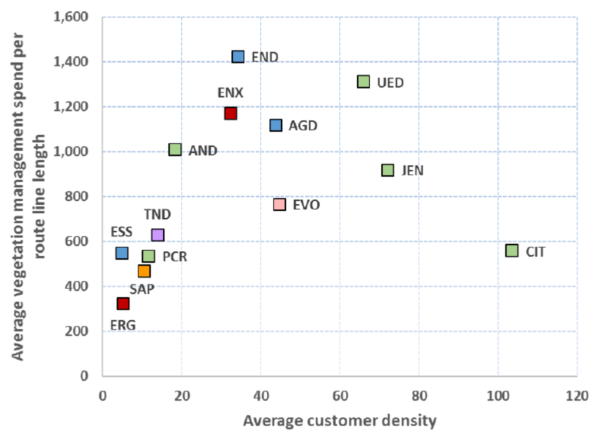
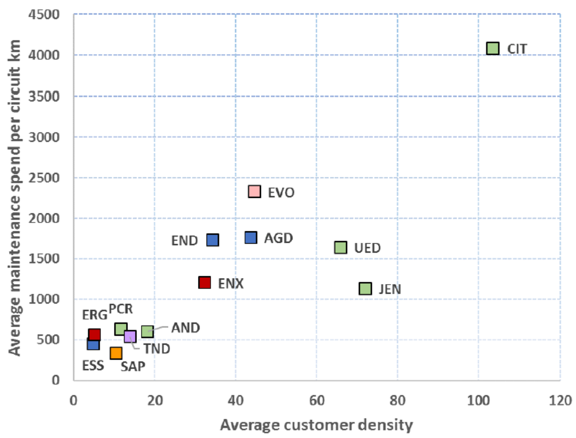


Figure 5.7 Average maintenance opex spend per circuit km against customer density ($2017)



[25] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, page 28.*
[26] Based on average DNSP overhead capitalisation and an average year of GSL inconvenience payments.
[27] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, pages 37-42.*
[28] *Ibid, pages 39-42.*

Figure 5.8 Average emergency response spend per interruption against customer density ($2017)

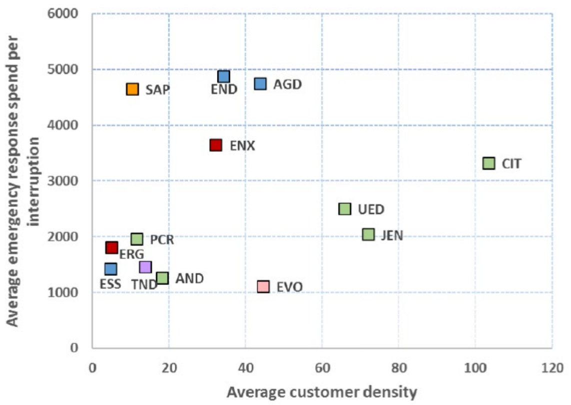
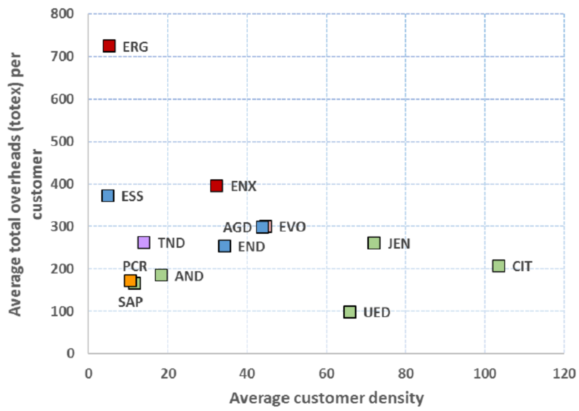


Figure 5.9 Total Overheads – average total overheads per customer against average customer density ($2017)



During our customer engagement, we were frequently asked to provide bottom-up analysis of opex. In our stakeholder workshops, we provided internally generated benchmarking information from data provided in response to the AER's RINs. Our benchmarked outcomes were generally consistent with the AER's category specific PPIs reported in the 2018 Report.

Rather than comparing opex costs only, the AER presented total overhead costs allocated to the total of capex and opex in its analysis, to ensure that differences in DNSP capitalisation policies do not affect the analysis.[29] We are encouraged by this approach as it measures the relative efficiency of overhead functions irrespective of internal policy. This is consistent with our view of our capitalisation policy as a material OEF, and the 2018 Report demonstrates that our total overhead costs are lower per customer as compared to most DNSPs.

We submitted to the AER during the development of its 2018 Report that the measurement of emergency response costs on a 'spend per interruption' basis is misleading. Interruptions are reported on a feeder type basis, and emergency response spend per interruption for rural feeders will be adversely impacted by the increased travel and time spent locating faults associated with longer lines with fewer customers. We proposed that measurement per kilometre of line would provide a more appropriate comparison of emergency response performance.

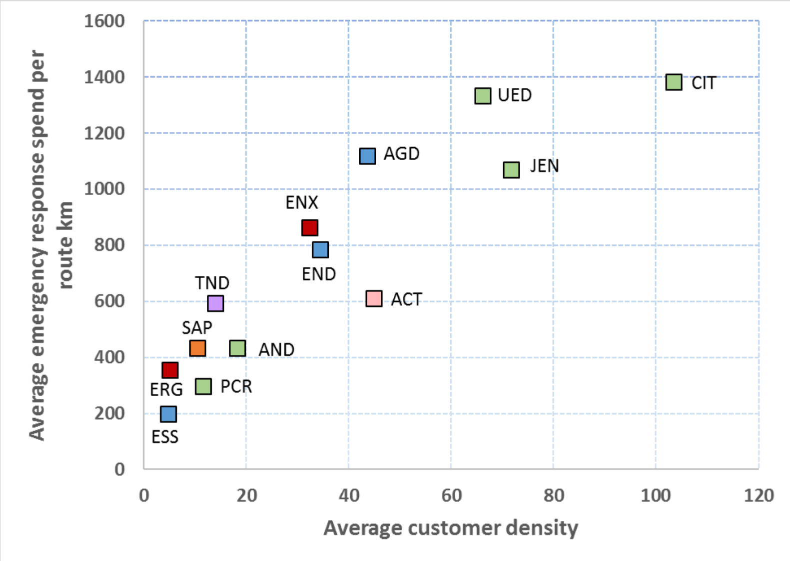
In its 2018 Report, the AER responded that while emergency response per route line length (kilometre) may account for the further travel distance of rural DNSPs to get to its feeders, urban DNSPs may face longer travel time due to congestion.[30] This may be true for travel time but is unlikely to hold for locating faults over widely dispersed assets in the case of rural DNSPs.

Further, we also advised the AER that SA Power Networks only records interruptions greater than one minute, in line with our reporting requirements for our Service Target Performance Incentive Scheme (**STPIS**), rather than the 0.5 seconds defined for sustained interruptions for the Category Analysis RIN,[31] which may mean that data is not comparable across DNSPs. The AER acknowledges that differences in how DNSPs interpret and report category level data will impact the category level benchmarking results and will consider data consistency issues and the materiality of this as part of its ongoing benchmarking development program.[32]

When emergency response costs are measured against route line length, consistent with other network opex activities, SA Power Networks is again shown to be one of the lowest cost DNSPs over the 2013-2017 period, displayed in Figure 6-7 below.

[29] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, page 41.*
[30] *Ibid, page 40.*
[31] *AER, Final Category Analysis RIN for distribution network service providers, March 2014, page 41.*
[32] *AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, page 42.*

Figure 6-7: Average emergency response spend per km of route line length[33]



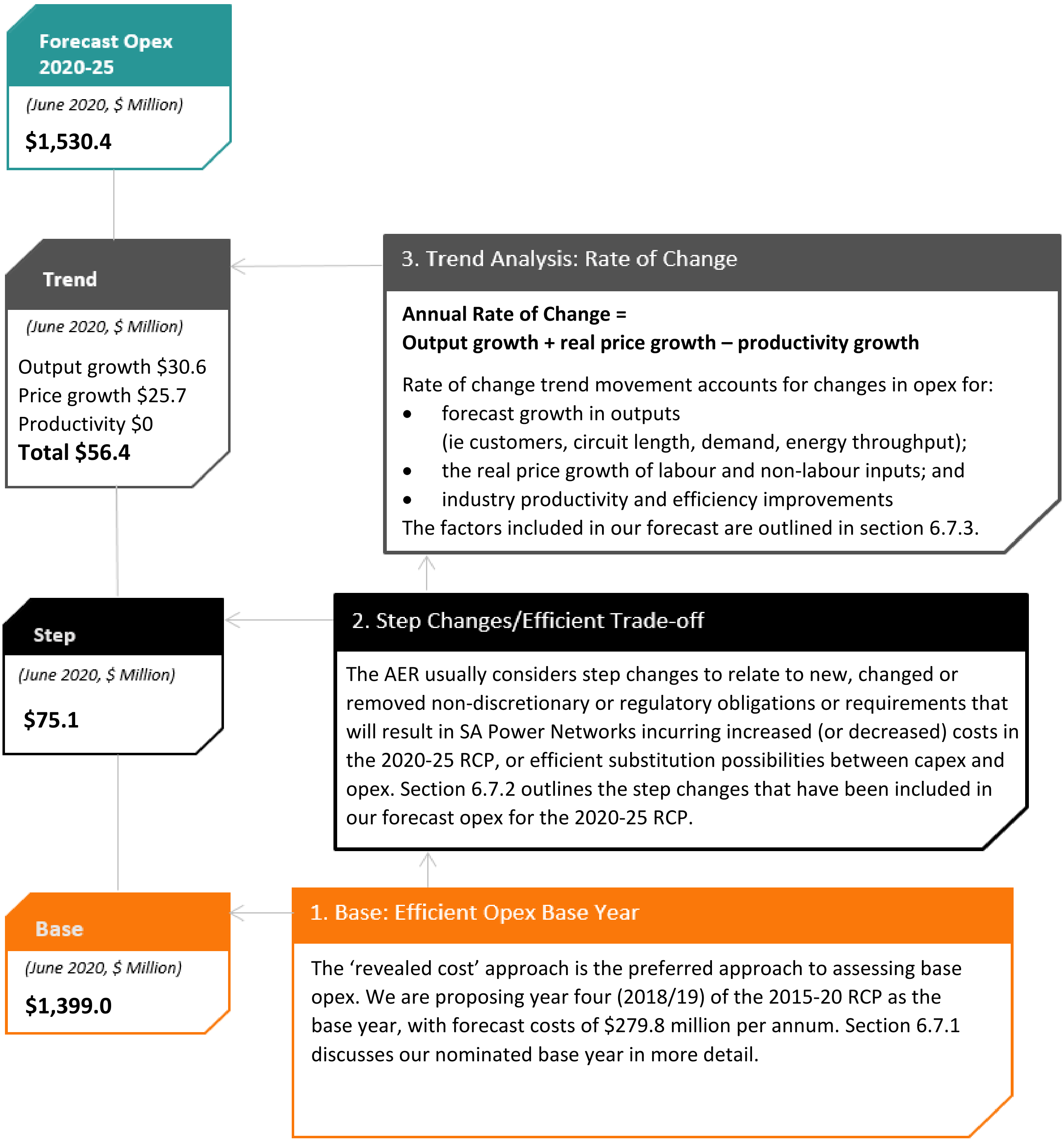
The MTFP and MPFP opex benchmarking results reported in the 2018 Report demonstrate that SA Power Networks is one of the most efficient DNSPs in the NEM. The additional category specific PPIs further confirm that we are consistently one of the lowest cost DNSPs across all levels of opex. Our revealed opex is therefore shown to be comparatively efficient. This supports that our base year costs are efficient and should be accepted by the AER.

[33] *SA Power Networks calculations using AER 2018 distribution partial performance indicators.xlsx file, ie* *https://www.aer.gov.au/system/files/AER%202018%20distribution%20benchmarking%20partial%20performance%20indicators%20-%20November%202018.xlsx*

6.7 Opex forecast for 2020-25 RCP

The EFAG sets out the intended approach to assessing opex in accordance with the NER.[34] We have applied the AER base-step-trend methodology as outlined in the EFAG to prepare our opex forecast for the 2020-25 RCP (Figure 6-8).[35]

Figure 6-8: Opex base-step-trend methodology



[34] *AER, Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013.*
[35] Forecasts for category specific opex using an alternative method to the base-step-trend methodology (eg debt raising costs) are discussed in 'Attachment 3 - Rate of Return and financing costs'.

6.7.1 Base year

We have nominated the 2018/19 regulatory year as our base year. The base year must reflect a suitable foundation for the forecast opex for the 2020-25 RCP. We believe that the 2018/19 regulatory year best represents this as it:

- will be the most recent regulatory year for which actual audited data will be available for the AER's final decision;
- best reflects the future costs required to efficiently maintain and operate our network; and
- incorporates the efficiency gains that we will have achieved up to 30 June 2019.

The expenditure levels in earlier regulatory years of the 2015-20 RCP do not provide an adequate base for the 2020-25 RCP due to the atypical factors highlighted in section 6.5.

For our 2018/19 proposed base year, we have forecast opex by applying a combination of year-to-date actuals and budgets.[36] One exception to this is our approach to forecasting GSL expenditure. Due to the volatility in our GSL inconvenience payments, resulting from unpredictable weather outcomes, our estimate of GSL expenditure for 2018/19 has been based on a five-year average of historical payments.[37]

To establish an efficient 'revealed year' for controllable costs, base year opex is adjusted to remove any non-recurrent costs. We have not included any non-recurrent costs in our forecast base year costs for the 2018/19 regulatory year. The application of the Efficiency Benefit Sharing Scheme (**EBSS**) requires an estimate of the actual opex for the final regulatory year (2019/20) of the 2015-20 RCP. We have therefore also added to our base year opex forecast an amount for the incremental adjustment for final regulatory year (2019/20) expenditure in the 2015-20 RCP.

Our base year opex complies with the requirements of the Reset RIN and has been calculated in accordance with our approved Cost Allocation Method.

Our Revised Proposal, due to be submitted in December 2019, will incorporate our actual opex for the 2018/19 regulatory year and any required adjustments.

6.7.2 Step changes

The electricity industry is dynamic and constantly evolving. New technologies are emerging, consumer preferences are shifting, and regulatory obligations and Government energy policies and programs continue to evolve. Where there are material cost increases or decreases, including for example those associated with changes driven by new, changed or removed regulatory obligations that are not captured in our base year opex or in the rate of change, step changes may be added (or subtracted) to reasonably reflect the opex criteria. Step changes may also be made for any efficient capex/opex trade-offs that require additional opex that will be offset by lower capital costs to achieve overall business efficiencies.

We have assessed our step changes, in accordance with the EFAG, to ensure that we have not double counted costs included in other elements of our opex forecast. Specifically, our step changes do not double count the costs of increased volume or scale, increased regulatory burden accounted for in forecast productivity or costs of discretionary changes in inputs.

During our customer engagement program, we discussed the early development of our proposed step changes. Many customers and stakeholders provided feedback on the merits and drivers of our proposed

[36] At the time of submitting this Proposal the actual results for the 2018/19 regulatory year were not available.
[37] GSLs for the 2018/19 forecast base year have been estimated based on an average of actual opex reported for the five years from 2013/14 to 2017/18. Should actual GSL costs in 2018/19 be abnormally low or high we will apply a non-recurrent efficiency gain for these costs in our Revised Proposal.

step changes. Responding to the feedback received, we removed and amended some of the proposed step changes discussed in our initial information sessions and contained in our 2020-2025 Draft Plan. Specifically, we removed the:

- customer engagement technologies step change; and
- billing system step change

More detailed information on the overall benefits to customers was requested for the remaining proposed step changes. This information is contained within the individual business cases for these step changes and has been included as supporting documentation to this Proposal.

In accordance with clause S6.1.3(1) of the NER, we have identified a number of significant interactions between our forecast capex and opex programs for the 2020-25 RCP.[38] The rationale for our capex programs for the 2020-25 RCP is discussed in Attachment 5 – Capital expenditure. Some of these programs require an increase in associated opex when compared to the 2015-20 RCP but avoid significant further uplifts in future opex that would occur if the proposed capex was not undertaken.[39] Our proposed step changes identify several of these capex/opex trade-offs that are explained further below. The AER is required by clauses 6.5.6(e) and 6.5.7(e) of the NER to have regard to these substitution possibilities between capex and opex when assessing our forecasts.

In developing our proposed step changes, we have also considered, and made provision for, efficient and prudent non-network options where possible.[40]

Table 6-3 provides an overview of our proposed step changes. The following paragraphs provide an explanation of each step change and references the applicable business cases. Appendix A further details the drivers of the proposed step changes, along with customer and stakeholder feedback received during our engagement and explains how we responded to this feedback.

Table 6-3: SA Power Networks summary of step changes for the 2020-25 RCP

(June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Total
LV Management	-	0.4	0.9	1.1	1.3	**3.8**
Cloud Transition – Hosting	1.0	1.2	1.6	1.7	1.8	**7.2**
Cloud Transition – Scheduling	0.8	0.8	0.8	0.8	0.8	**3.8**
Cable and Conductor minor repair	14.2	13.5	13.5	13.5	13.5	**68.2**
Critical Infrastructure Compliance	2.4	2.4	2.4	2.4	2.4	**12.1**
GSL Reliability	(4.0)	(4.0)	(4.0)	(4.0)	(4.0)	**(19.9)**
Step Change	**14.3**	**14.3**	**15.3**	**15.5**	**15.8**	**75.1**

6.7.2.1 LV Management – Enabling the energy transition

In Attachment 5 – Capital expenditure and our supporting business case (5.18 - LV Management Business case) we have proposed expenditure for the 2020-25 RCP to develop new operational systems and business processes to actively manage the integration of solar, battery storage and virtual power plants (**VPPs**) into the distribution network.

Specifically, this involves expenditure to:

---

[38] For example, our asset replacement/refurbishment program assesses the replacement or refurbishment (life extension) of assets to ensure that all network risks are adequately identified and managed in accordance with the business risk profile (Supporting Document 5.8 Powerline Asset Management Plan).

[39] The LV Management step change is a clear example for this statement. If that program of work is not undertaken (ie the 'do nothing' option) it would lead to increased costs for consumers and markets as a whole, and also potentially for SAPN in putting in place reactive systems to constrain customers and the market from using the LV network. For more information refer to Supporting Document 5.18 LV Management Business Case.

[40] *NER, clause 6.5.6(3)(10).*

- improve visibility of the LV network through targeted monitoring, primarily through the procurement of data from smart meter providers and other third parties;
- develop a LV network model to understand the 'hosting capacity' of our network;[41]
- put in place a register of Distributed Energy Resources (**DERs**); and
- implement open interfaces (eg Application Programming Interfaces, (**APIs**)) to publish dynamic export limits to customers and DER aggregators.

The 'identified need' for this expenditure is to:

- comply with our regulatory obligations to ensure that the ongoing uptake of solar and batteries, and the synchronised operation of batteries by third party VPP operators do not lead to unacceptable degradation in the quality, reliability or security of supply for customers; and
- comply with these regulatory obligations in a manner that will maximise benefits for consumers and the market as a whole, and address the challenges created by the integration of solar, battery storage and VPP at the lowest cost to all our customers (both with and without DER) in the long-term.

The LV Management business case examines a number of alternative approaches to meeting the identified need and finds that our proposed approach, which includes the management of DER exports within existing network capacity using dynamic export limits, represents the best long-term outcome for all customers (both with and without DER) under a range of possible future scenarios. This approach achieves greater value for customers than continuing with static export limits while avoiding the high capital cost of augmenting the capacity of the network that would otherwise be required.[42]

> *"Very important to plan how the distribution network will accommodate an expected large increase in distributed energy. Monitoring LV network is a start. Agree procuring voltage monitoring services from retailers and third parties likely to be economic, especially with more sophisticated monitoring equipment in homes."* **Residential customer submission via Talking Power**

This expenditure is predominantly by way of capex ($31.8 million $June 2020, over the 2020-25 RCP). However, there is an associated and inter-dependent step change in ongoing opex ($3.8 million $June 2020, over the 2020-25 RCP). This opex is appropriately characterised as a step change as it is required to implement the selected option to achieve the identified need. The specific components to this opex are as follows:

- $2.6 million (total for the 2020-25 RCP) represents an efficient trade-off between capex and opex. This pertains to our proposed approach to achieving visibility of voltage in the LV network through the procurement of data from competitive smart meter providers and other third parties (including costs associated with the systems and processes required to enable this data acquisition). This is an efficient opex based non-network alternative to capex on SA Power Networks owned monitoring devices, consistent with our overarching strategy to seek market-based alternatives to avoid network capex wherever it is efficient to do so.
- $0.5 million (total for the 2020-25 RCP) is for required staff and systems associated with operation of a DER register which is a new regulatory requirement arising from a 2018 rule change.[43]
- $0.5 million (total for the 2020-25 RCP) is for the ongoing opex for staff and other costs associated with maintaining the model of LV network topology and hosting capacity limits.

---

[41] That is, how much energy can be fed into the network by embedded generators like solar and batteries at any given point in time before voltage issues or other problems arise. This varies from one local LV area to the next according to a range of factors, such as the type of network construction and the nature of the loads connected to the local network.

[42] In this sense, the preferred option of 'dynamic limits' is itself an alternative to much larger capex of 'adding capacity'.

[43] *AEMC, National Electricity Amendment (register of distributed energy resources) Rule 2018 No. 9 made by AEMC on 13 September 2018.*

- $0.2 million (total for the 2020-25 RCP) is for the ongoing opex for operating the systems associated with LV network constraint calculation and publication of dynamic export limits to small embedded generators, aggregators and VPP operators via an open API.

Throughout our customer engagement program, we have sought feedback on the challenges and opportunities presented by customer use of DER and have continually refined our approach[44]. Since we released our preliminary expenditure forecasts, the opex cost component of our approach has been reduced in the order of $22 million. Overall, our extensive and industry-leading engagement has resulted in our plans to transition the network being broadly supported by customers and stakeholders, as further outlined in our Supporting Document 5.18 LV Management Business Case.

6.7.2.2 Cloud Transition – Cloud Hosting

The constantly changing Information and Communications Technology (**ICT**) environment now means that more ICT businesses are only providing access to their ICT software applications through cloud subscription services, meaning that they can no longer be 'owned' and installed locally. Reliable ICT infrastructure underpins the delivery of all services which are critical to the effective operation and maintenance of our network and the management of network outages. Growing global dependence on ICT has seen an increase in systems that are relied upon to gather, store and analyse information. This information either needs to be stored by businesses on internal hardware, resulting in recurrent capex or through cloud subscription services know as Software-as-a-Service (**SaaS**).

The most cost-effective way to approach growing information requirements, is by replacing hardware in onsite data centres with cloud hosting services. Cloud infrastructure is a subscription based operating cost. By moving to this approach, we can reduce our ongoing capital investment costs associated with updating and replacement of hardware. Our option analysis shows that a measured move to cloud hosting for the 2020-25 RCP offers a benefit to customers through lower costs. We have proposed this approach as we believe it represents the lowest long-term cost to customers and is the most appropriate investment required to achieve the expenditure objectives. The additional opex of $7.2m ($June 2020) that we have included in our opex forecast is more than offset by a reduction in our forecast of recurrent ICT capex of $7.8 million ($June 2020).

Our cost benefit and options analysis for this capex/opex trade-off are included in Supporting Document 6.1 –IT Infrastructure Refresh Business Case.

6.7.2.3 Cloud Transition – Work Scheduling

Our Digital Strategy outlines key focus areas to enable the organisation to achieve its prudent strategic outcomes in an increasingly digital world. We will leverage digital technologies to more cost efficiently deliver services while managing the risks on our network. As mentioned above, the constantly changing ICT environment now means that more ICT businesses are only providing access to their ICT software applications through cloud subscription services. The benefit of cloud applications is that they require less capital outlay during establishment and upgrades. However, they do require more opex due to subscription licence costs.

In particular, our enterprise system for field work scheduling and management has reached the end of its life in 2018 and the replacement option is only available through a cloud service. The replacement of this software will not be complete until the end of 2019 and therefore the associated increase in cost to move to the cloud service will not be captured in our 2018/19 base year costs. The additional opex of $3.8 million

---

[44] *See "Customer and stakeholder engagement report" and see "Supporting Document 0.16 - Newgate Research Community attitudes toward Solar"*

($June 2020) that we have included in our opex forecast is offset by a reduction in our forecast of recurrent ICT capex of $3.8 million ($June 2020).

This step change captures the substitution costs to cover the opex subscription licence costs in place of the foregone capex. Our cost benefit and options analysis for this capex/opex trade-off are included in Supporting Document 6.2 – IT Applications Refresh Business Case.

6.7.2.4 Cable and conductor minor repair costs – reclassification from capex to opex

In December 2018, the AER completed its review of the regulatory tax approach and released its final report (**Final Tax Report**).[45] The Final Tax Report recognised that the recommended changes to the AER's regulatory tax approach might give rise to material adverse consequences such as inter-generational inequities (eg a short term benefit to current customers at the expense of future customers) and cash-flow concerns for DNSPs.[46] For this reason, the AER contemplated that other aspects of a DNSP's proposal might be reviewed and changed to ensure a balanced outcome is reached for the benefit of both customers and DNSPs in the long term.[47]

As a consequence of the Final Tax Report, we have reviewed other aspects of our Proposal to ensure that a balanced outcome is reached for the long-term benefit of customers (both current and future) and our regulated network business. That review has identified a number of issues that, if not addressed, may have material adverse consequences for both customers and our regulated network business over the long term.

As a result, SA Power Networks is proposing (amongst other things) to change the treatment of certain cable and conductor minor repair costs from capex to opex; ie the proposal is to now treat these costs as opex rather than capex because treating these costs as opex better reflects the nature of this type of expenditure and helps to address potential inter-generational inequities that could be caused by continuing to treat this type of expenditure as capex.

Cable and conductor minor repair costs cover expenditure on repairs to cables and conductors:

- due to an asset failure; and
- identified defects that could result in an imminent asset failure (if not repaired).

As noted above, we consider that the inter-generational equity concerns raised during the AER's tax review warrant re-categorising this type of expenditure as opex rather than capex. Cable and conductor minor repairs is more akin to repairs and maintenance rather than refurbishment, and essentially only benefits current customers. For these reasons, SA Power Networks has removed this type of expenditure from its replacement expenditure (**repex**) forecast and has included a capex/opex trade-off step change in its opex forecast for the 2020-25 RCP for this type of expenditure.

This expenditure is required in order for SA Power Networks to meet or manage the expected demand for SCS over the 2020-25 RCP, to comply with its regulatory obligations associated with the provision of SCS or otherwise maintain the quality, reliability and security of supply of those services, and to maintain the safety of its distribution system through the supply of SCS. It also reflects the efficient and prudent costs of achieving these opex objectives and is a realistic expectation of the forecast and cost inputs for repair and refurbishment of cables and conductors that are detailed in Attachment 5 – Capital Expenditure and other supporting documents to this Proposal.

The additional opex of $68.2 million ($June 2020) that we have included in our opex forecast is offset by a reduction in our forecast of repex (and therefore capex) of $69.9 million ($June 2020).

[45] *AER, Final report – Review of regulatory tax approach, 17 December 2018.*
[46] *Ibid, p 65 to78.*
[47] *Ibid, p 70.*

As discussed in further detail in Attachment 7 –Corporate income tax, SA Power Networks believes that the interrelated changes to our corporate income tax allowance and opex forecast are in the long-term interests of customers as they better reflect the actual work undertaken, without imposing material and inappropriate additional costs on future customers. In other words, an appropriate balance between the interests of current and future customers (ie inter-generational equity) will be achieved by adopting these changes which ensure that both current and future customers only pay costs relevant to the delivery of the services they receive.

Finally, we note that:

- these changes are net present value (**NPV**) neutral (further details of this calculation are available on request by the AER); and
- this capex/opex trade-off step change will also lead to a lower RAB at the end of the 2020-25 RCP and therefore a lower return on capital and depreciation over time.

This will benefit customers in the long term and once again help achieve inter-generational equity.

6.7.2.5 Critical Infrastructure Compliance

In 2017 a series of requirements were introduced to address the national security risks associated with foreign involvement (for example, through ownership, offshoring, outsourcing and supply chain arrangements) in relation to critical infrastructure (the **new critical infrastructure system and data control obligations**).[48] SA Power Networks' distribution system is classified as a high priority Australian critical infrastructure asset under the new critical infrastructure system and data control obligations.

As an identified 'Critical Infrastructure Provider', we are required to work with the Critical Infrastructure Centre (**CIC**) to collaboratively develop and implement risk mitigation strategies. The CIC is also able to safeguard against national security risks by leveraging existing and new regulatory mechanisms, including through its role in government decision making under the new *Security of Critical Infrastructure Act 2018* (Cth) (**SCI Act**) and Foreign Investment Review Board under the *Foreign Acquisitions and Takeovers Act 1975* (Cth) (**FATA**). These regulatory frameworks require SA Power Networks to comply with the new critical infrastructure system and data control obligations which require SA Power Networks to (amongst other things) use ICT systems and support arrangements that are based in Australia.

SA Power Networks currently has arrangements in place for the delivery and/or provision of ICT services that do not comply with the new critical infrastructure system and data control obligations, and the requirement to use ICT systems and support arrangements in Australia in particular. We currently engage overseas suppliers for support and hosting services for core systems because these were the most efficient options for accessing these types of services. Sourcing support overseas assists in keeping the cost for ICT services down. However, to achieve compliance with the new critical infrastructure system and data control obligations, various changes will need to be made to our ICT systems and services.

We have been working collaboratively with the CIC since May 2017 to:

- identify the national security risks related to foreign involvement in our distribution system (such as the risks posed by our engagement of overseas suppliers); and
- develop a strategy to address the new critical infrastructure system and data control obligations and the aims and objectives of the CIC and SCI Act more generally.

As a result of this collaboration, we have prepared a list of non-compliant systems and operational functions and have agreed with the CIC to implement a 'treatment plan'. Aspects of the treatment plan

[48] The new critical infrastructure system and data control obligations are explained in detail in Supporting Document 6.3 – Critical Infrastructure Obligation Business Case.

relating to capex have been implemented in the 2015-20 RCP. However, there are a number of aspects relating to ongoing opex that are required to be implemented in the 2020-25 RCP under the terms of the treatment plan and the compliance dates agreed with the CIC. This step change only relates to those aspects of the treatment plan that materially impact opex and have not been accounted for in our 2018/19 base year costs.

The impact of this change and the costs of the associated step change were discussed during our customer engagement program at both our opex and ICT deep dive workshops. Observations from our independent facilitator, Think Human, included the following customer feedback: [49]

> *"Participants recognised that cyber security is a necessary expense and that the energy market is at high risk. They encouraged SAPN to explore whether solutions at a national level could be simultaneously more efficient in terms of expenditure and be more effective. Participants also wanted to know how risks changed as SAPN moved increasingly to cloud computing and storage."*

The critical infrastructure system and data control obligations are new regulatory obligations or requirements as defined in the National Electricity Law (**NEL**) and are associated with the provision of SCS. They will result in an increase of $12.1 million ($June 2020) in operating costs in the 2020-25 RCP and therefore, constitute a step change in opex (over and above the level of opex in our base year). Details of the new critical infrastructure system and data control obligations, the options we analysed to meet these obligations and our cost benefit analysis are included in Supporting Documents 6.3 – Critical Infrastructure Obligations Business Case and 6.3.1 – FIRB Electricity Business Security Committee C23: 2018 Compliance Report.

6.7.2.6 GSL Reliability Duration Payments

Prior to the commencement of each new RCP, ESCoSA reviews the reliability service standards that will apply to SA Power Networks. To better target customers with ongoing, persistent reliability issues, ESCoSA has reviewed and amended the GSL scheme to apply for the 2020-25 RCP. [50]

The current standard includes five types of GSL inconvenience payments, with two specifically relating to network reliability: the duration of interruption payments (**duration payments**) and frequency of interruption payments (**frequency payments**). Duration payments account for 97 per cent of all GSL costs. As a result, these payments have the largest impact on the volatility of GSL expenditure. The changes applied by ESCoSA to the GSL scheme for 2020-25 RCP are included in Table 6-4 below.

Table 6-4: ESCoSA Final Decision on GSL scheme for the 2020-25 RCP

GSL Scheme	Changes to the scheme for the 2020-25 RCP
Duration payments	Removed duration payments in their current form (per event) and replaced with total annual duration payments, to apply at the end of each regulatory year. Revised thresholds and values will apply for these outage payments.
Frequency payments	Frequency payments thresholds will be simplified, with one level of payment instead of three.
Late attendance appointments	Removed GSL payment for 2020-25 RCP.
Timeliness of new connections	Continue with the GSL payment for 2020-25 RCP.
Repair of faulty street light(s)	Continue with the GSL payment for 2020-25 RCP.

[49] *Think Human, Information technology deep dive workshop report, SA Power Networks, June 2018, page 14.*
[50] *ESCoSA, SA Power Networks reliability standards review, Final decision, January 2019, page 35.*

However, these new standards will not take effect until 1 July 2020 and the costs of the current GSL scheme are included in the 'revealed year' costs. Therefore, we propose a negative step change of $19.9 million ($June 2020) to account for the changes to our GSL regulatory obligations for the 2020-25 RCP. To determine the efficient adjustment to be applied for the base year opex we have re-cast our GSL expenditure based on the new regulatory obligations. Using these values, we have applied a reduction to our opex forecast based on a five-year average.[51] Stakeholders have indicated they are supportive of this revised approach.

The assumptions and calculations for this step change can be found in Supporting Document 6.4 - GSL step change 2020-25.

6.7.3 Rate of change

We have adopted a rate of change approach which is consistent with the rate of change formula in the EFAG.[52] Outlined below are the individual forecast approaches we applied for output growth, real price growth and productivity growth. These forecasts represent the efficient changes in opex over time, ensuring that our total opex over the 2020-25 RCP reflects the opex objectives and criteria. In addition, our forecast reflects a balanced approach that achieves the NEO to promote efficient investment in, and efficient operation and use of, our electricity services for the long term interests of our customers.[53] It also meets the Revenue and Pricing Principles in the NEL to provide us with a reasonable opportunity to recover at least the efficient costs we incur in providing those services and complying with our regulatory obligations or requirements.[54]

6.7.3.1 Output growth

Our base year opex forecast reflects the costs required to operate and maintain current outputs. An output growth factor is applied to our opex forecast to account for changes in output levels over the 2020-25 RCP. In recent determinations made by the AER a 'refined' approach to forecasting annual output growth has been applied, [55] calculating an average of the specification and weights from four benchmarking models rather than one econometric model.

The AER has stated that this refinement reflects concerns raised by the Consumer Challenge Panel and the Australian Competition Tribunal.[56] The Consumer Challenge Panel has raised concerns regarding the weighting applied to customer numbers under the previous approach and has encouraged the AER to test whether the weights are reasonable. The AER's response has been to apply an average of weightings from the four models it uses to measure benchmarking efficiency. The AER states that this also addresses a concern of the Australian Competition Tribunal about the reliance on a single model, raised during the 2015 merits review of the NSW distribution determinations.[57]

Table 6-5, shows the 2018 benchmarking weightings for the four econometric models that have been used in recent determinations.[58]

---

[51] Consistent with our forecast approach to GSL expenditure in the base year, we have re-cast the expenditure from 2013/14 to 2017/18 and applied an average reduction. The Revised Proposal will report the actual results for the 2018/19 regulatory year, and the GSL step change will account for any variation between the five-year average incorporating the base year actual costs.
[52] *AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013, page 23.*
[53] *National Electricity Law, section 7.*
[54] *National Electricity Law, section 7A.*
[55] *AER, Draft decision, Ausgrid distribution determination 2019-24, Attachment 6, November 2018, page 6-37 to 6-39.*
[56] *Ibid, page 6-39.*
[57] *Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79, [285].*
[58] The weightings applied in the draft determinations were based on 2017 weightings but recognised that they would be updated for the final determinations when the 2018 Report was released.

Table 6-5: AER output specifications and weights derived from economic benchmarking models[59]

Output*	MPFP	SFACD	LSECD	LSETLG
Customer Numbers	31.00%	70.80%	67.59%	51.52%
Circuit length	29.00%	16.81%	11.78%	13.86%
Ratcheted maximum demand	28.00%	12.39%	20.63%	34.62%
Energy throughput	12.00%			

*MPFP = Multilateral partial factor productivity, SFACD = Cobb Douglas stochastic frontier analysis, LSECD = Cobb Douglas least squares estimation, LSETLG = Translog least squares estimation.

The AER has not afforded an opportunity for DNSPs to engage with this change in output weight measurement. SA Power Networks is concerned that averaging models that apply different techniques, in particular adding a model (ie opex MPFP) that contains an additional measure (ie energy throughput), to the other econometric models will not provide SA Power Networks with the opportunity to recover its efficient costs of achieving the opex objectives as required under the opex criteria.[60]

We have not applied the AER's latest methodology as we do not agree that applying the weights from all four models is representative of the efficient costs required to provide SCS and does not satisfy the opex criteria.

We engaged NERA Economic Consulting (**NERA**) to review the AER's approach and their proposed changes to output weightings. NERA's advice is that the MPFP and translog models (as currently designed), as well as the use of energy throughput as a driver, will not reasonably reflect costs that an efficient DNSP would incur, for the following key reasons:[61]

- The MPFP model weights are unlikely to reflect the drivers of costs of an efficient DNSP. The drivers that have been included in this model were chosen based on tariff structure, not by assessing their effect on DNSP costs. The process for deriving the weights used in this modelling has been opaque, with the weights artificially constrained to be positive, masking possible misspecification in the model. The MPFP weights are also estimated with very little data, suggesting the weights are estimated imprecisely.
- Changes in energy throughput do not drive changes in DNSPs' efficient operating costs. Historically the growth in energy throughput may have approximated the growth in peak demand. However, the recent developments in the sector have altered the traditional load profiles. Due to the growing use of DER, network wide changes in energy throughput no longer accurately predict proportionate changes in peak demand or DNSP costs.
- The translog model weights are unlikely to reflect the drivers of costs of an efficient DNSP. Noting that the AER has not considered whether the coefficients in the model imply intuitive engineering or economic relationships and by choosing weights only based on "first-order" coefficients, the AER's cost indexation approach is not consistent with its economic results.

Attached as Supporting Document 6.5, is NERA's full report reviewing the AER's proposed output weightings (see Supporting Document 6.5 - NERA - Review of the AERs Proposed Output Weightings)

Additionally, the significant transformation that the electricity industry is undergoing means that the output drivers may no longer be tracking the underlying drivers of DNSPs operating costs. For SA Power Networks, this is particularly the case with ratcheted maximum demand and energy throughput. The traditional model of centralised generation being transmitted and distributed 'one way' to customers is rapidly changing with a significant amount of solar and, increasingly, batteries being connected to our distribution network. These outcomes contribute significantly to the decline in our productivity performance as measured by the AER's benchmarking.

---

[59] *Economic Insights, Economic benchmarking results for the Australian Energy Regulator's 2018 DNSP annual benchmarking report, November 2018, scaled to sum to 1.0.*
[60] *NER, clause 6.5.6(c).*
[61] *NERA Economic Consulting, Review of the AER's proposed output weightings, November 2018, page iv.*

To achieve the opex criteria objectives and provide a proportionate solution to the issues raised to the AER, our proposed output growth forecast applies an average of the weightings from the two Cobb-Douglas models (SFACD and LSECD included in Table 6-5 above). This approach addresses the Tribunal's criticism that the AER has relied too heavily on a single model, as it recommends the averaging of two models. The two models recommended do imply similar weights on customer numbers, suggesting that the recommended approach does not address the concerns raised by the Consumer Challenge Panel. However, these concerns were not supported by compelling evidence that the model over-estimated the importance of customer numbers. Of the four models included in the AER's determinations, the two most robust models (the Cobb-Douglas models as explained in NERA's report) [62] apply similar weights on customer numbers and appear to provide stronger evidence than the evidence presented in the Consumer Challenge Panel's critique.

Applying the average of these two models provides output growth weightings of: customer numbers 69.20%, circuit length 14.30% and ratcheted maximum demand 16.51%. Table 6-6 below shows the output growth factors that have been used to develop our forecast opex for the 2020-25 RCP.

Table 6-6: SA Power Networks forecast output growth for the 2020-25 RCP

(June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Average/ Total
Ratcheted maximum demand %	-	-	-	-	-	-
Circuit line length %	0.37%	0.38%	0.38%	0.38%	0.39%	0.38%
Customer numbers %	1.18 %	0.99%	0.78%	0.77%	0.76%	0.90%
Weighted output growth %	**0.87%**	**0.74%**	**0.59%**	**0.59%**	**0.58%**	**0.67%**
Output growth ($m)	**$2.4**	**$4.5**	**$6.2**	**$7.9**	**$9.6**	**$30.6**

In our view, these forecast output growth escalators reflect a realistic expectation of the cost inputs required to achieve the opex objectives.[63]

6.7.3.2 Real price growth

A real price change adjusts the base opex to account for forecast changes in input costs above or below CPI. Customers and stakeholders did not support any increase above CPI for price inputs during our customer engagement process. We accept this view for non-labour costs only for the 2020-25 RCP and have included a real increase in labour price growth, based on independent expert forecasts. This affords us an opportunity to recover a realistic expectation of our cost inputs in accordance with the NER.[64]

Our opex forecast adopts the AER forecast price growth weightings of 59.7 per cent labour and 40.3 per cent non-labour. These weightings are consistent with recent AER determinations. Table 6-7 below, displays the real price growth included in our forecast opex based on these weightings. Further detail on how we have derived these weightings is contained in the next section.

Table 6-7: SA Power Networks forecast real price growth for the 2020-25 RCP

(June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Average/ Total
Labour price growth %	0.78%	1.07%	1.21%	1.09%	0.96%	1.02%
Non-labour price growth %	-	-	-	-	-	-
Weighted real price growth%	**0.47%**	**0.64%**	**0.72%**	**0.65%**	**0.58%**	**0.61%**
Real price growth ($m)	**$1.3**	**$3.1**	**$5.2**	**$7.1**	**$8.9**	**$25.7**

[62] *NERA Economic Consulting, Review of the AER's proposed output weightings, November 2018, page iv.*
[63] *NER 6.5.6(c)(3).*
[64] *NER 6.5.6(c)(3).*

6.7.3.2.1 Labour price growth

To forecast labour price growth, we engaged BIS Oxford Economics to provide an outlook and forecasts for the Wage Price Index (**WPI**) for the Electricity, Gas, Water and Waste Services (**EGWWS**) at the national level and for South Australia. The Australian Bureau of Statistics (**ABS**), does not provide WPI data for the utilities sectors in South Australia.

DNSPs operate in a dynamic industry to deliver services to customers. Much of the work is performed on or near energised assets in a high-risk environment, where safety to both the public and workers is of paramount importance. A real labour price increase reflects the high skill levels, contribution to meeting customer demands for a safe and reliable network, and adaptability to technological change for workers in our industry. Consistent with recent AER determinations, we have adopted an average of BIS Oxford Economics and Deloitte Access Economics' (**DAE**)[65] utilities sector labour price growth forecasts.

A copy of BIS Oxford Economics' full report is included as Supporting Document 6.6 (see Supporting Document 6.6 - BIS Oxford Economics - Utilities Construction Wage Forecasts to 2024-25). Our DAE forecasts are based on the report prepared for the AER and applied in the final determination for ElectraNet's 2018-23 RCP (as relevant to South Australia),[66] with the final two years an average of the 2020 to 2023 period.

Table 6-8: SA Power Networks annual labour price growth for the 2020-25 RCP

	2020/21	2021/22	2022/23	2023/24	2024/25
BIS Oxford Economics %	1.16%	1.53%	1.72%	1.62%	1.36%
Deloitte Access Economics %	0.40%	0.60%	0.70%	0.57%	0.57%
Average labour price growth %	**0.78%**	**1.07%**	**1.21%**	**1.09%**	**0.96%**

6.7.3.2.2 Non-labour price growth

For the 2020-25 RCP we are forecasting non-labour costs will increase in line with CPI (ie. no real price increase).

We are concerned however with the impact that a falling Australian Dollar may have on imported materials such as steel, transformers and cable. We will continue to monitor this throughout the regulatory determination process.

6.7.3.3 Productivity growth

A productivity growth factor is included in the trend component of opex forecasting. The intent of the productivity growth forecast is to reflect the productivity improvements that all efficient and prudent DNSPs can reasonably achieve, by focussing on whether the productivity frontier is shifting rather than the performance of inefficient DNSPs 'catching-up' to the frontier.[67]

The AER published a draft decision setting out its proposed approach to forecasting productivity growth for DNSPs in November 2018.[68] A final decision is not scheduled to be made by the AER until February/March 2019 (ie after the lodgement of this Proposal).

[65] *Deloitte Access Economics, Labour price forecasts prepared for the Australian Energy Regulator, 7 February 2018, page 74. Noting: DAE forecast only provides escalations to 2022/23, an average of the forecast for the regulatory years between 2020-2023 has been applied for the remaining two regulatory years.*

[66] *Deloitte Access Economics, labour Price Forecasts prepared for the Australian Energy Regulator, 7 February 2018, page 74. Note that forecasts are only reported up to 2022/23; AER, ElectraNet Transmission final determination 2018-23, Overview, April 2018, page 26.*

[67] *AER, Better Regulation, Explanatory Statement: Expenditure Forecast Assessment Guideline, November 2013, page 65 and 66.*

[68] *AER, Draft decision paper: Forecasting productivity growth for electricity distributors, November 2018.*

In its draft decision, the AER proposed and sought views on a number of measures that could be used to determine a forecast of productivity growth and proposed that a pre-emptive productivity adjustment of 1 percent be applied for the next RCP of each DNSP.[69]

The AER's draft decision noted its intent to:[70]

- apply the productivity growth forecast it arrived at through its consultation process to the final determinations that the AER will publish for DNSPs in April 2019;
- provide the relevant DNSPs with an opportunity to submit their views on how the AER should apply its final decision on productivity growth to their specific circumstances; and
- take those submissions into account in its final distribution determinations for those DNSPs.

SA Power Networks understands that the AER will adopt a similar approach in relation to the SA Power Networks distribution determination, namely the AER will:

- apply the productivity growth forecast it arrives at through its consultation process in its draft determination for the SA Power Networks distribution determination;
- provide SA Power Networks with an opportunity to submit its views on how the AER should apply its final decision on productivity growth to SA Power Networks' specific circumstances in SA Power Networks' Revised Proposal; and
- take SA Power Networks' submissions into account in its final determination for SA Power Networks.

SA Power Networks lodged a submission in response to the AER's draft decision on 21 December 2018.[71] In that submission we set out our view that:

- none of the AER's proposed productivity measures comply with the NEL nor NER. In particular, the proposed measures do not have regard to:
    - section 7A of the NEL, that requires that DNSPs be provided with a reasonable opportunity to recover at least the efficient costs the DNSP incurs in providing direct control services; and
    - the opex and capex criteria in clauses 6.5.6 and 6.5.7 of the NER, that requires the AER to accept a forecast that reflects a realistic expectation of the cost inputs required by an efficient and prudent DNSP to achieve the opex and capex objectives;[72]
- the AER's approach must consider the interrelationships with other components of its distribution determination, and how it affects various aspects of the incentive regulation framework. This includes, reviewing the approach to cost pass throughs, step changes, use of 'output' factors, and how risks are compensated via the Weighted Average Cost of Capital (**WACC**); and
- the available evidence does not justify application of a positive productivity adjustment (that is, a pre-emptive cut to our forecast opex).

Consistent with our submissions in response to the AER's draft decision,[73] we have included a proposed opex productivity growth factor of 0.0% in our opex forecast. While customers and stakeholders have suggested that a positive productivity growth factor should be considered for the 2020-25 RCP, we have formed the view that this cannot be justified taking into account the available evidence and the other issues raised in our submission in response to the AER's draft decision.

[69] *AER, Draft decision paper: Forecasting productivity growth for electricity distributors, November 2018, page 7.*
[70] *Ibid.*
[71] *Refer: https://www.aer.gov.au/system/files/SAPN20-20SubmissiontotheAEROpexProductivityGrowthForecastReviewDraftDecisionPaper20-21December2018.pdf*
[72] *NER 6.5.6(c) and 6.5.7(c).*
[73] *Refer: https://www.aer.gov.au/system/files/SAPN20-20SubmissiontotheAEROpexProductivityGrowthForecastReviewDraftDecisionPaper20-21December2018.pdf*

Table 6-9: SA Power Networks forecast productivity growth for the 2020-25 RCP

(June 2020, $ million)	2020/21	2021/22	2022/23	2023/24	2024/25	Average/ Total
Productivity growth %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Productivity growth ($m)	-	-	-	-	-	-

6.8 Relationship with Efficiency Benefit Sharing Scheme (EBSS)

Once opex allowances are set, the Efficiency Benefit Sharing Scheme (**EBSS**) may be applied to incentivise DNSPs to find ongoing operating efficiencies and therefore incur less opex than the allowance. DNSPs that can maintain and operate their networks at a lower cost than their allowance (and still meet applicable service standards), retain the benefit of the lower costs during the balance of the relevant RCP. Customers will then gain through lower opex allowances in the subsequent RCP as the EBSS allows DNSPs to retain only around 30% of the benefit of lower costs, with the remaining 70% passed back to customers via lower prices.

As detailed in Attachment 8 - EBSS, SA Power Networks proposes that the EBSS continue to operate and be applied for the 2020-25 RCP.

6.9 Related Party

SA Power Networks is a related party to CKI/HEI Electricity Distribution Services Pty Ltd (**CHED Services**) though our parent companies. SA Power Networks has had the following arm's-length contracts with CHED Services since 2005:

- FRC Shared Services Agreement;
- FRC IT Support Systems Services; and
- Contact Centre Services Agreement.

An independent report has been obtained by SA Power Networks which confirms that these agreements have been negotiated and contracted on commercial and arms' length terms and verifies that the services provided to SA Power Networks under these agreements are provided on a cost-effective basis. The independent report is contained in Supporting Document 6.7 – KPMG Independent Analysis of Service Arrangements.

Due to the introduction of the AER's Ring-fencing Guideline, the following wholly-owned subsidiaries of SA Power Networks (collectively referred to as Enerven) were created from 1 January 2018, predominately to provide non-distribution services:

- Enerven Energy Infrastructure Pty Ltd; and
- Enerven Energy Solutions Pty Ltd.

Enerven's predecessor was the internally separate Construction and Maintenance Services (**CaMS**) department within SA Power Networks. CaMS had traditionally provided some discrete inputs to SA Power Networks regulated distribution services which form part of our opex, primarily in the areas of telecommunications, maintenance and emergency response. Since its establishment, the Enerven delivered portion of total SCS opex is around 0.5%.[74]

[74] To 30 June 2018.

Shortened Forms

2018 Report	*2018 Annual Benchmarking Report*
ABS	*Australian Bureau of Statistics*
AER	*Australian Energy Regulator*
API	*Application Programming Interface*
CaMS	*Construction and Maintenance Services*
Capex	*Capital expenditure*
CIC	*Critical Infrastructure Centre*
CPI	*Consumer Price Index*
DAE	*Deloitte Access Economics*
DER	*Distributed Energy Resources*
DNSP	*Distribution network service provider*
EBSS	*Efficiency Benefit Sharing Scheme*
EFAG	*Expenditure Forecast Assessment Guideline*
EGWWS	*Electricity, Gas, Water and Waste Services*
ESCoSA	*Essential Services Commission of South Australia*
FATA	*Foreign Acquisitions and Takeovers Act 1975* (Cth)
Final Tax Report	*AER, Final report – Review of regulatory tax approach*
GSL	*Guaranteed Service Level*
ICT	*Information and Communications Technology*
LSECD	*Cobb Douglas least squares estimation*
LSETLG	*Translog least squares estimation*
LV	*Low Voltage*
MPFP	*Multi-lateral partial factor productivity*
MTFP	*Multi-lateral total factor productivity*
NEL	*National Electricity Law*
NEM	*National Electricity Market*
NEO	*National Electricity Objective*
NER	*National Electricity Rules*
NERA	*NERA Economic Consulting*
NPV	*Net present value*
OEFs	*Operating Environment Factors*
Opex	*Operating expenditure*
PPI	*Partial performance indicator*
Proposal	*Regulatory Proposal for the 2020-25 RCP*
RAB	*Regulatory asset base*
RBA	*Reserve Bank of Australia*
RCP	*Regulatory Control Period*
Repex	*Replacement expenditure*
Revised Proposal	*Revised Regulatory Proposal for the 2020-25 RCP*
RIN	*Regulatory Information Notice*
SaaS	*Software-as-a-Service*
SAPN CCP	*SA Power Networks' Customer Consultative Panel*
SCI Act	*Security of Critical Infrastructure Act 2018* (Cth)
SCS	*Standard control services*
SFACD	*Cobb Douglas stochastic frontier analysis*
STPIS	*Service Target Performance Incentive Scheme*
VPP	*Virtual Power Plants*
WACC	*Weighted Average Cost of Capital*
WPI	*Wage Price Index*

Appendix A. Step change summary

Step change	Driver	Total (June 2020, $ Million)	Capex savings (June 2020, $ Million)	What we heard	Our response/evidence
LV management future networks (6.7.2.1)	Capex/opex trade-off and positive NPV	3.8	-	Requests for SA Power Networks to seek a lower cost alternative that provides visibility of new customer technologies.	We have refined our forecast to include a simplified solution that will provide performance impacts at a lower cost. This solution has reduced forecast opex by $6.3m as compared to the 2020-2025 Draft Plan.
Cloud transition – cloud hosting (6.7.2.2)	Capex/opex trade-off	7.2	7.8	Acceptance that 'Cloud' is a sound strategic option to deliver ICT services in flexible and cost-efficient way but expect AER to thoroughly review efficiency of trade-off.	A business case detailing the options and our cost benefit analysis has been included with our Proposal. The refinement of our forecast cost since our 2020-2025 Draft Plan has led to a reduction in opex of $0.3m.
Cloud transition – work scheduling (6.7.2.3)	Capex/opex trade-off	3.8	3.8	Acceptance that 'Cloud' is a sound strategic option to deliver ICT services in flexible and cost-efficient way but expect AER to thoroughly review efficiency of trade-off.	A business case detailing the options and our cost benefit analysis has been included with our Proposal. The refinement of our forecast cost since our 2020-2025 Draft Plan has led to an increase in opex of $0.7m.
Cable and conductor minor repair costs – reclassified from capex to opex (6.7.2.4)	Capex/opex trade-off	68.2	69.9	Aspects of our Proposal have been reviewed and changed following the outcomes of the AER's Final Tax Report to ensure a balanced outcome is reached for both the benefit of customers and our regulated network business in the long-term. We have proposed changes to address inter-generational equity and cash-flow concerns and the AER will consider the resulting capex/opex step changes in the normal way during the revenue determination process.	We have proposed a change to our treatment so that cable and conductor minor repair costs are accounted for as opex rather than capex. Details in relation to this proposed step change have been included in this Proposal.
Critical infrastructure compliance (6.7.2.5)	Change in regulatory obligations	12.1	-	Acceptance that this change will cause SA Power Networks to incur additional costs. Forecast needs to be as prudent as possible and build-up of forecast to be clearly outlined in Proposal supporting documents.	A business case detailing the options and cost benefit analysis has been included with our Proposal. A refinement of our forecast has led to an increase of $1.5m.
GSL reliability duration payments (6.7.2.6)	Change in regulatory obligation	(19.9)	-	Customers have been engaged as part of the ongoing review by ESCoSA. Stakeholders have indicated to us they are supportive of the reduction in GSL inconvenience payments.	Our approach to forecasting GSLs was discussed with the AER. This solution has increased the forecast opex by $2.1m as compared to the forecast opex in the 2020-2025 Draft Plan. Calculations for the annual GSL step change are provided as a supporting document to this Proposal.

Step change	Driver	Total (June 2020, $ Million)	Capex savings (June 2020, $ Million)	What we heard	Our response/evidence
Billing Replacement	Opex associated with ongoing capex program for legacy billing system replacement	~~3.4~~	-	Concerns that the expenditure did not fit the definition of a step change.	Any additional opex costs associated with the billing system replacement in the 2020-25 RCP will be absorbed. Removing this step change has reduced our forecast opex by $3.4m as compared to the forecast opex in the 2020-2025 Draft Plan.
Customer Engagement Technologies	Capex/opex trade-off for improved customer information	~~2.5~~	-	Concerns that the expenditure did not fit the definition of a step change.	Removed from opex forecast. Not supported by customers and stakeholders. No longer proposed.
TOTAL		75.1	81.5		