DRAFT DECISION

SA Power Networks
Distribution Determination
2020 to 2025

Attachment 6
Operating expenditure

October 2019

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to SA Power Networks for the 2020–2025 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

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Attachment 16 – Negotiated services framework and criteria

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP14	Consumer Challenge Panel, sub-panel 14
CPI	consumer price index
DMIAM	demand management innovation allowance (mechanism)
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
GSL	guaranteed service levels
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicator
PTRM	post-tax revenue model
repex	replacement expenditure
RIN	regulatory information notice
SCS	standard control services

6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex for standard control services is one of the building blocks we use to determine a service provider's annual total revenue requirement.

This attachment outlines our assessment of SA Power Networks' proposed opex forecast for the 2020–25 regulatory control period.

6.1 Draft decision

We do not accept SA Power Networks' distribution opex forecast of $1551.0 million ($2019–20)[1] for the 2020–25 regulatory control period because we are not satisfied that it reflects the opex criteria.[2]

Our alternative estimate of total opex is $1472.9 million ($2019–20). This is $78.1 million, or 5.0 per cent, lower than SA Power Networks' forecast. We are satisfied our alternative estimate of forecast opex reasonably reflects the opex criteria. Table 6.1 sets out SA Power Networks' proposal and our alternative estimate for the draft decision.

Table 6.1 Comparison of SA Power Networks' proposal and our draft decision on opex ($ million, 2019–20)

Opex category	SA Power Networks proposal	AER draft decision	Difference ($)
Base (reported opex in 2018–19)	1381.0	1381.0	–
2018–19 to 2019–20 increment	18.0	16.6	–1.4
Trend: Output growth	30.6	25.6	– 5.0
Trend: Real price growth	25.7	9.7	– 16.0
Trend: Productivity growth	–	– 20.8	– 20.8
Step changes	75.1	53.6	– 21.5
Total opex (excluding debt raising costs)	1530.4	1465.7	– 64.7
Debt raising costs	20.5	7.2	–13.3
Total opex (including debt raising costs)	1551.0	1472.9	– 78.1

1 Including debt raising costs; SA Power Networks, 2020-25 *Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 7.

2 NER, cl. 6.5.6(c).

Source: SA Power Networks, *2020–25 Regulatory proposal – RIN 1 – Workbook 1 – Regulatory determination template 2020–25*, February 2019; SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019; AER analysis.

Note: Numbers may not add up to totals due to rounding.

Figure 6.1 shows SA Power Networks' opex forecast, its actual opex, our previous regulatory decisions and our alternative estimate that is the basis for our draft decision.

Figure 6.1 SA Power Networks' opex over time ($ million, 2019–20)

Source: SA Power Networks, *2020–25 Regulatory proposal – RIN 1 – Workbook 1 – Regulatory determination template 2020–25,* February 2019; SA Power Networks, *Information request 005*, 26 February 2019; AER analysis.

Note: Includes debt raising costs.

The following factors have contributed to our lower alternative total opex forecast:

- Our forecast rate of change by which we trend opex over the 2020–25 regulatory control period is 0.3 per cent per year, which is lower than SA Power Networks' proposed 1.3 per cent per year. This difference is due to:
  - We used our standard approach (using output weights from all of our benchmarking models) to forecast expected increases in the costs of operating a larger network (output growth). SA Power Networks proposed an alternative approach that used the weights from only two of our benchmarking models.
  - We used forecasts of real labour price growth in the utilities sector in South Australia prepared for us by Deloitte Access Economic (Deloitte). This is a change from our approach in previous determinations of averaging the forecasts from Deloitte and the business's consultant (generally BIS Oxford

Economics) which SA Power Networks proposed. Our current analysis shows that over the period 2007 to 2018, Deloitte's real Wage Price Index (WPI) growth forecasts have been more accurate than the result obtained from averaging the forecasts.

    - We applied the 0.5 per cent per year productivity growth forecast from our opex productivity growth review final decision.[3] Although SA Power Networks did not adopt our productivity growth forecast in its proposal, it has since advised that it will adopt the 0.5 per cent per year forecast in its revised proposal.[4]

- We have accepted the need for all six step changes proposed by SA Power Networks. However, we have reduced some of SA Power Networks' proposed amounts as some increases were not well justified. We have reduced the amount proposed for the step change relating to the reclassification of cable and conductor minor repairs from repex to opex to reflect past actual expenditure. We have also adjusted the amount SA Power Networks proposed for the step change relating to its Guaranteed Service Level (GSL) reliability payments by using a longer historical averaging period to better forecast future payments.
- Our forecast of debt raising costs of $7.2 million ($2019–20) is $13.3 million ($2019–20) less than the $20.5 million ($2019–20) proposed by SA Power Networks. We have maintained our standard approach for estimating debt raising cost. We do not consider that the available evidence supports SA Power Networks' proposed allowance for debt raising costs.

6.2 SA Power Networks' proposal

SA Power Networks used a 'base–step–trend' approach to forecast opex for the 2020–25 regulatory control period, consistent with our preferred approach.

In applying our base–step–trend approach to forecast opex for the 2020–25 regulatory control period, SA Power Networks:

- Used estimated opex in 2018–19 as the base to forecast[5]
- Applied the approach in the *Expenditure forecast assessment guideline for electricity distribution* (the Expenditure Assessment Guideline) to calculate the final year increment (being the difference the forecast opex for 2019–20 and 2018–19) to derive the starting point for its opex forecast.[6] This increased its base opex forecast by $18.0 million ($2019–20)[7]

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[3] AER, *Final decision paper – Forecasting productivity growth for electricity distributors*, March 2019, p. 9.

[4] SA Power Networks, *Letter to AER – SA Power Networks Regulatory Proposal 2020–25*, 3 June 2019.

[5] SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 22.

[6] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 22–23.

[7] SA Power Networks, *2020–25 Regulatory proposal – RIN 1 – Workbook 1 – Regulatory determination template 2020–25,* February 2019.

- Applied its forecast rate of change to its opex forecast, consistent with the Expenditure Assessment Guideline.[8] This increased its opex forecast by $56.3 million ($2019–20), including real price growth of $25.7 million, output growth of $30.6 million and zero productivity growth[9]
- Proposed six step changes related to cloud transition, LV management, critical infrastructure compliance, cable and conductor minor repairs and GSL reliability payments.[10] This increased its opex forecast by $75.1 million ($2019–20)
- Proposed an opex category specific forecast for debt raising costs, which increased its opex forecast by $20.5 million ($2019–20).[11]

Excluding debt raising costs, SA Power Networks' total opex forecast is $1530.4 million ($2019-20) for the 2020–25 regulatory control period (See Table 6.2). SA Power Networks is forecasting a 15.6 per cent higher opex in the 2020–25 regulatory control period compared to its estimated opex in the 2015–20 regulatory control period.[12] Opex represents 39.6 per cent of SA Power Networks' total revenue proposal.[13]

Table 6.2 SA Power Networks' proposed opex ($ million, 2019–20)

	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Opex excluding category specific forecasts	297.9	301.7	306.5	310.3	314.0	1530.4
Debt raising costs	4.0	4.1	4.1	4.1	4.1	20.5
Total opex	**301.9**	**305.8**	**310.6**	**314.4**	**318.1**	**1551.0**

Source: SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating expenditure*, 31 January 2019.

Note: Numbers may not add up to total due to rounding.

Figure 6.2 shows the different components in SA Power Networks' opex proposal ($ million, 2019–20).

8 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 23–24.

9 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 7.

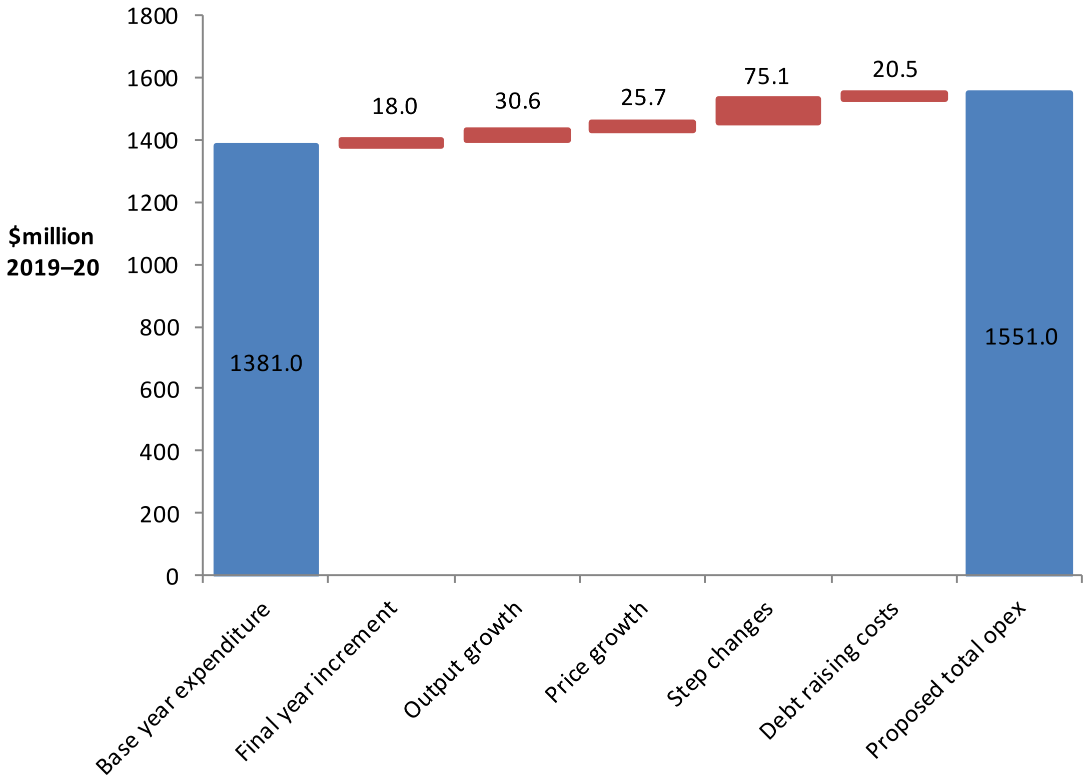
10 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, pp. 22-23; SA Power Networks, *2020–25 Regulatory proposal – Supporting document 6.8 – Opex SEM model 2020–25 RCP,* January 2019.

11 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 7; SA Power Networks, *2020–25 Regulatory proposal – Supporting document 1.1 – PTRM model*, January 2019.

12 This excludes debt raising costs. See SA Power Networks, *Information request 005*, 26 February 2019.

13 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 1.1 – PTRM model*, January 2019.

Figure 6.2 SA Power Networks' opex forecast



Source: SA Power Networks, *2020-25 Regulatory proposal – RIN 1 – Workbook 1 – Regulatory determination template 2020-25*, February 2019; SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019; AER analysis.

6.2.1 Stakeholder views

We received thirty three submissions on SA Power Networks' 2020–25 regulatory proposal and a number of them raised issues on opex. At a high level, the submissions broadly supported SA Power Networks’ base opex proposal but sought greater scrutiny by the AER of the proposed trend adjustments and step changes. We have taken these submissions, and any other concerns consumers identified in the course of SA Power Networks' and our engagement into account in developing the positions set out in this draft decision.[14] A summary of the opex issues raised in submissions is provided in Table 6.3.

[14] NER, cl. 6.5.6(e)(5A).

Table 6.3 Submissions on SA Power Networks' opex proposal

Stakeholder	Issue	Description
South Australian Council of Social Services (SACOSS), Energy Consumers Australia (ECA), The Energy Project, Uniting Communities, SA Financial Counsellors Association (SAFCA), SA Minister for Energy and Mining, Business SA, South Australian Wine Industry Association (SAWIA)	Base opex	Most submissions considered SA Power Networks' base opex to be relatively efficient, but noted its opex productivity has been declining over time. Some submissions suggested that given the declining opex productivity, and the higher opex proposed in 2018–19, the AER should examine base opex more closely[15] Corporate and vegetation management costs increases should be fully examined[16] Some submissions considered that none of the operating environment factors included in the 2018 Annual Benchmarking Report, with the exception of vegetation management, should apply to SA Power Networks.[17] Others were of the view that as per SA Power Networks' proposal, its low capitalisation of overheads and aged network should be taken into account[18]
CCP14, SACOSS, ECA, The Energy Project, Uniting Communities, SAFCA, Businesses SA, SAWIA	Price growth	The AER's general approach to forecasting labour price growth (averaging the forecasts of its consultant and the businesses' consultant) should be examined and the drivers of the different forecasts of labour price growth from these consultants (particularly the relatively high estimates from BIS Oxford Economics) should be evaluated[19] Observed wage growth is subdued and this should be taken into account in forecasting future labour price growth with some submissions asking whether real labour cost increases are necessary[20]

15 South Australian Council of Social Service, *SACOSS submission in response to AER Issues Paper on the SAPN electricity determination 2020–25*, 10 May 2019, pp. 2–3.

16 Government of South Australia*, Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25*, 16 May 2019, p. 3; Business SA Chamber of Commerce and Industry South Australia, *Business SA submission to AER on SA Power Networks 2020-25 Regulatory Proposal*, May 2019, p. 8; South Australian Wine Industry Association, *Submission in response to the Issue Paper on SA Power Networks' Regulatory Proposal for 2020–25*, 15 May 2019, p. 4.

17 South Australian Council of Social Service, *SACOSS submission in response to AER Issues Paper on the SAPN electricity determination 2020–25*, 10 May 2019, p. 3.

18 Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission,* May 2019; Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020–25 regulatory proposal*, May 2019, pp. 28–29.

19 CCP14, *Advice to the AER on the SA Power Networks' 2020–25 regulatory proposal*, 16 May 2019, p. 33; Business SA Chamber of Commerce and Industry South Australia, *Business SA submission to AER on SA Power Networks 2020–25 regulatory proposal*, May 2019, p. 10; Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission*, May 2019, p. 18; Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020–25 regulatory proposal*, May 2019, p. 31.

20 South Australian Council of Social Service , *SACOSS submission in response to AER Issues Paper on the SAPN electricity determination 2020–2025*, 10 May 2019, pp. 11–13; Partnership of SA Financial Counsellors Association, The Energy Project and Uniting Communities, *Submission: Issues Paper – SA Power, Networks*

Stakeholder	Issue	Description
		The use of a benchmark weighting of labour to non-labour costs (59 to 41 per cent) should be considered given SA Power Network has a lower actual weighting of labour costs[21]
CCP14, SACOSS, ECA, SAWIA, Central Irrigation Trust	Productivity growth	The AER's opex productivity growth from the industry wide review (0.5 per cent per year) should be applied, particularly given the proposed Information and Communications Technology (ICT) that provides opportunities for efficiencies to be realised[22]
SACOSS, ECA	Cable and conductor minor repairs step change	The AER needs to be convinced that the activity is opex related and the benefits only accrue to customers in the 2020–25 regulatory control period and do not extend the life of the asset[23] It is not clear the nature of the activities in the cable and conductor minor repair category have changed to make them opex[24]
CCP14, ECA, The Energy Project, Uniting Communities, SAFCA, SA Minister for Energy and Mining	Critical infrastructure step change	The new Commonwealth Government requirements around cybersecurity mean this is a legitimate step change. One submission suggested consulting with the Critical Infrastructure Centre[25] The cost estimates for this step change should be closely scrutinised[26]
CCP14, ECA	Cloud hosting and work	Some submissions considered further substantiation is required to ensure the step change requirements are met while others considered sufficient evidence has been provided of the benefits of transitioning to the cloud for these services[27]

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revenue determination 2020–2025, 22 May 2019, p. 21; South Australian Wine Industry Association, *Submission in response to the Issue Paper on SA Power Networks' Regulatory Proposal for 2020–25*, 15 May 2019, p. 4.

21 Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission,* May 2019; Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020–25 regulatory proposal*, May 2019, p. 31.

22 CCP14, *Advice to the AER on the SA Power Networks' 2020–25 regulatory proposal*, 16 May 2019, pp. 14, 34; South Australian Council of Social Service, *SACOSS submission in response to AER Issues Paper on the SAPN electricity determination 2020-25*, 10 May 2019, p. 4; Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission, May 2019*; Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020–25 regulatory proposal*, May 2019, p. 31; South Australian Wine Industry Association, *Submission in response to the Issue Paper on SA Power Networks' Regulatory Proposal for 2020–25*, 15 May 2019, pp. 2, 4; Central Irrigation Trust, *CIT Submission to SA Power Networks Regulatory Proposal (2020–25)*, 15 April 2019, pp. 1–2.

23 South Australian Council of Social Service, *SACOSS submission in response to AER Issues paper on the SAPN electricity determination 2020-25*, 10 May 2019, p. 4; Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission*, May 2019, p. 17.

24 South Australian Council of Social Service, *SACOSS submission in response to AER Issues paper on the SAPN electricity determination 2020-25*, 10 May 2019, p. 4; Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission,* May 2019, p. 18.

25 CCP14, *Advice to the AER on the SA Power Networks' 2020–25 regulatory proposal*, 16 May 2019, p. 33; Partnership of SA Financial Counsellors Association, The Energy Project and Uniting Communities, *Submission: Issues Paper – SA Power, Networks revenue determination 2020–2025*, 22 May 2019, p. 21; Government of South Australia*, Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25*, 16 May 2019, p. 4.

26 Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission*, May 2019, p. 18.

Stakeholder	Issue	Description
	scheduling step changes	The project timing and cost estimates should be scrutinised[28]
CCP14, SACOSS, ECA, SA Minister for Energy and Mining, Clean Energy Council, TESLA, Redback Technologies, GreenSync, Energy Australia	LV management step change	If the capex is approved the key issues to examine for the opex step change are the proposed staffing requirements and their salary levels[29] Some submissions considered the AER should take a cautious view to its capex assessment and ensure that all of SA Power Networks' LV management capex (and opex) proposals are considered in an integrated and holistic manner.[30] Other submissions were very supportive of the proposed LV management capex and considered that there was a clear and demonstrated need for dynamic management and that the costs are relatively low[31]
ECA, The Energy Project, Uniting Communities, SAFCA	GSL reliability payments step change	Essential Service Commission of South Australia's changes to the GSL scheme mean this is a legitimate step change[32] The underlying calculations for the GSL cost reductions should be scrutinised[33]

6.3 Assessment approach

6.3.1 Incentive regulation and the 'top-down' approach

Incentive regulation is designed to prevent network businesses from exploiting their natural monopoly position by setting prices in excess of efficient costs.[34] A key feature

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27 CCP14, *Advice to the AER on the SA Power Networks' 2020–25 regulatory proposal*, 16 May 2019, pp. 32, 45; Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission*, May 2019, p. 18; Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020-25 regulatory proposal*, May 2019, p. 30.

28 Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission*, May 2019, p. 18; Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020–25 regulatory proposal*, May 2019, p. 30.

29 Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission*, May 2019, p. 18.

30 CCP14, *Advice to the AER on the SA Power Networks' 2020–25 regulatory proposal*, 16 May 2019, p. 32; CCP14, *Response to the SA Power Networks (SAPN) approach to the challenges of the high penetration of embedded generation as part of their 2020–25 regulatory proposal early engagement*, 29 June 2018, pp. 4–5; South Australian Council of Social Service, *SACOSS submission in response to AER Issues paper on the SAPN electricity determination 2020-25*, May 2019, p. 9.

31 Government of South Australia, *Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020–25*, p. 1; Clean Energy Council, *Submission to the AER Issues Paper: SA electricity distribution determination*, *SA Power Networks 2020–2025*, May 2019, pp. 1–8: Tesla, *SA Power Networks: 2020–2025 Regulatory Proposal*, May 2019, pp. 1–8; Redback Technologies, *Submission in response to SAPN regulatory proposal*, May 2019, pp. 1–3; GreenSync, *SA Power Networks 2020–25 Regulatory Proposal*, May 2019, pp. 1–4; Energy Australia, *SA Power Networks' revenue proposal for the 2020–25 regulatory control period*, May 2019, p. 2.

32 Partnership of SA Financial Counsellors Association, The Energy Project and Uniting Communities, *Submission: Issues Paper – SA Power, Networks revenue determination 2020–2025*, 22 May 2019, p. 21.

33 Energy Consumers Australia, *AER issue paper: SA Power Networks Electricity distribution determination 2020 to 2025 Submission*, May 2019, p.18; Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020–25 regulatory proposal*, May 2019, p. 30.

of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including electricity distribution networks. More specifically for opex, we rely on the efficiency incentives created by both ex ante revenue regulation (where an opex allowance is granted over a multi-year regulatory control period) and the efficiency benefit sharing scheme (EBSS).

The approach we apply to assessing a business's opex (and which we have applied in this draft decision) is more fully described in the Expenditure Assessment Guideline,[35] and its accompanying explanatory materials.

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us, the regulator.[36]

Incentive regulation encourages regulated businesses to reduce costs below the regulator's forecast, in order to make higher profits, and ‘reveal’ their costs in doing so. The information revealed by the businesses allows us to develop better expenditure forecasts over time. Revealed opex reflects the efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future regulatory control periods, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business’s commercial interests with consumer interests.

Our general approach is to assess the efficiency of the business’s forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects or programs. To do so, we develop an alternative estimate of total opex using forecasting method as set out in the Expenditure Assessment Guideline, known as the ‘base–step–trend’ approach (section 6.3.2). This is generally a 'top-down' approach, but there may be circumstances where we need to use bottom-up analysis, particularly in relation to our base opex assessment and for step changes.[37]

Benchmarking a network business against others in the National Electricity Market (NEM) provides an indication of whether revealed opex can be adopted as 'base opex' and, if not, what our alternative estimate of base opex should be. While benchmarking is a key tool, we use a combination of techniques to assess whether base opex reasonably reflects the opex criteria.[38] We may make a downward adjustment to the business’s revealed opex if we consider it is operating in a materially inefficient manner. Material inefficiency is a concept we introduced in our Expenditure Assessment Guideline.[39] We consider a service provider is materially inefficient when it

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[34] Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 188.

[35] AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013.

[36] Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 189.

[37] A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up'.

[38] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 12–14.

[39] AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

is not at, or close to, its peers on the efficiency frontier. We define this more precisely in the context of economic benchmarking below.

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[40] It allows the network businesses the flexibility to manage their assets and labour as they see fit to achieve the opex objectives in the NER (National Electricity Rules),[41] and more broadly, the National Electricity Objective (NEO).[42] This is consistent with the requirement that we consider whether *the total* opex forecast, and *not* the individual forecast opex components, reasonably reflects the opex criteria.[43]

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [44]

> The key feature of economic regulation of [distribution network service providers] in the NEM is that it is based on incentives rather than prescription…
>
> Importantly, under [incentive-based regulation], funding is not approved for [distribution network service providers'] specific projects or programs. Rather, a total revenue requirement is set, which is based on forecasts of total efficient expenditure. Once a total revenue is set, it is for the [business] to decide which suite of projects and programs are required to deliver services to consumers while meeting its regulatory obligations…

6.3.2 Base–step–trend forecasting approach

As a comparison tool to assess a business’s opex forecast, we develop an alternative estimate of the business's total opex requirements in the forecast regulatory control period, using the base–step–trend forecasting approach. We have regard to the opex factors set out in the NER in making this assessment.[45]

If the business adopts a different forecasting approach to derive its opex forecast, we develop an alternative estimate and assess any differences with the business's forecast opex.

Figure 6.3 summarises the base–step–trend forecasting approach.

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[40] Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, pp. 27–28.

[41] NER, cl. 6.5.6(a).

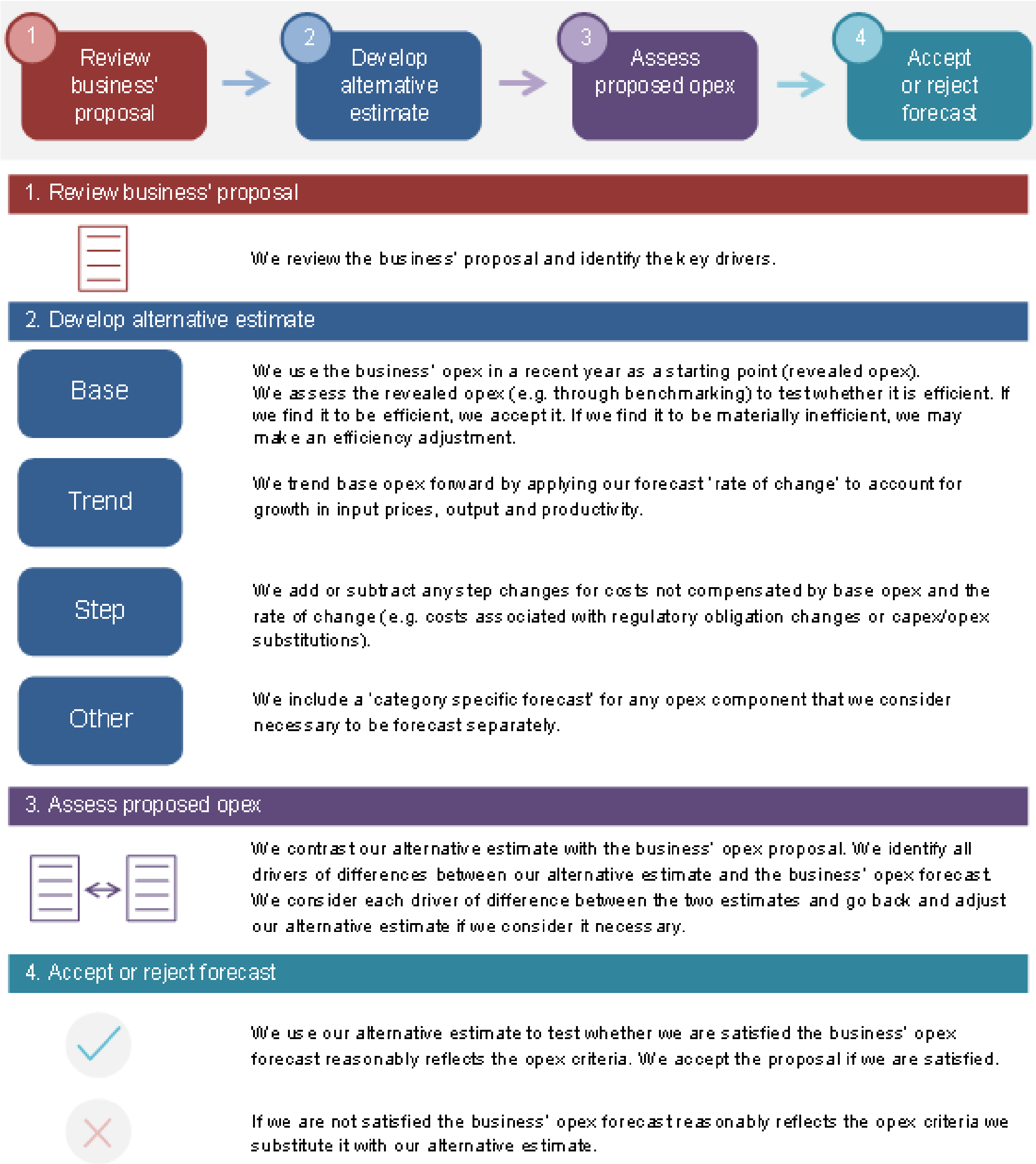
[42] NEL, s. 7.

[43] NER, cl. 6.5.6(c).

[44] AEMC, *Contestability of energy services, Consultation paper*, 15 December 2016, p. 32.

[45] NER, cl. 6.5.6(e).

Figure 6.3 Our opex assessment approach



Base opex

If we find the business is operating efficiently, our preferred methodology is to use the business's historical or 'revealed' costs in a recent year as a starting point for our opex forecast.[46] We must have regard to the opex factors in deciding whether we are satisfied that the business's proposed opex forecast reasonably reflects the opex criteria.[47]

46 NER, cl. 6.5.6(e)(5).
47 NER, cl. 6.5.6(e)(5).

We do not simply assume the business's revealed opex is efficient. It may include an ongoing level of inefficient expenditure. We use our benchmarking results[48] and other assessment techniques to test whether the business is operating efficiently.

We consider revealed opex in the base year is generally a good indicator of opex requirements over the next regulatory control period because the level of *total opex* is relatively stable from year to year. This reflects the broadly predictable and recurrent nature of opex.

A business may experience fluctuations in particular categories of opex, and the composition of total opex can change, from year to year. While many operation and maintenance activities are recurrent and non-volatile, some opex projects follow periodic cycles that may or may not occur in any given year, and some opex projects are non-recurrent.

Even if disaggregated opex categories have high volatility, the total opex varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects. Further, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year to year—to the extent they do not offset each other—by continually re-prioritising its work program, as would be expected in a workably competitive market. Our incentive-based, revealed cost, framework incentivises them to do so.

Rate of change

We trend base opex forward by applying our forecast 'rate of change'. We estimate the rate of change by forecasting the expected growth in input prices, outputs and productivity. We consider that the rate of change takes into account almost all relevant sources of opex growth.

We forecast input price growth using a combination of labour and non-labour price change forecasts. Labour costs represent a significant proportion of a distribution business’s costs.[49] To determine the input price weights for labour and non-labour prices, we have regard to the input price weights of a prudent and efficient benchmark business. Consistent with incentive regulation, this provides the business an incentive to adopt the most efficient mix of inputs throughout the regulatory control period.

We forecast output growth to account for the annual increase in output of services provided. The output measures used should, ideally, be the same measures used to forecast productivity growth.[50] Productivity measures the change in output for a given amount of input.

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48 NER, cl. 6.5.6(e)(4); AER, *Annual benchmarking report—Electricity distribution network service providers*, November 2018.

49 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 49.

50 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 23–24.

The output measures we typically use for distribution businesses are energy delivered, ratcheted maximum demand, customer numbers and circuit length.[51] We do not typically adjust forecast output growth for economies of scale because we account for these in our forecast of productivity growth.

Our forecast of opex productivity growth captures the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations. We generally base our estimate of productivity growth on recent productivity trends across the electricity industry. However, if we consider historic productivity growth does not represent 'business-as-usual' conditions we do not use it to forecast future productivity growth and may rely on other industry or economy wide indicators.

We recently reviewed our approach to forecasting opex productivity growth and determined that a forecast of 0.5 per cent per year reflects a reasonable forecast of the productivity growth a prudent and efficient electricity distributor can make. [52] We stated that we intended to adopt this opex productivity growth forecast when we review the opex forecasts proposed by electricity distributors going forward.[53]

Step changes and category-specific forecasts

Lastly, we add or subtract any components of opex that are not appropriately compensated for in base opex or the rate of change, but which should be included in the forecast total opex to meet the opex criteria.[54] These adjustments are in the form of 'step changes' or 'category-specific forecasts'.

Step changes

Step changes should not double count costs included in other elements of the total opex forecast. As explained in the Expenditure Assessment Guideline, the costs of increased volume or scale should be compensated for through the output growth component of the rate of change and it should not become a step change.[55] In addition, forecast productivity growth may account for the cost of increased regulatory obligations over time—that is, 'incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for higher costs resulting from changed obligations.'[56] Therefore, we consider only new costs that do not reflect the historic 'average' change as accounted for in the productivity growth forecast require step changes.[57]

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[51] These measures are discussed more fully in our benchmarking reports, see AER, *Annual Benchmarking Report – Electricity distribution network service* providers, November 2018, pp. 46–52.

[52] AER, *Final decision paper – Forecasting productivity growth for electricity distributors*, March 2019, pp. 8–11.

[53] AER, *Final decision paper – Forecasting productivity growth for electricity distributors*, March 2019, p. 11.

[54] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

[55] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

[56] AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

[57] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

To increase its maximum allowable revenue, a regulated business has an incentive to identify new costs not reflected in base opex or costs increasing at a greater rate than the rate of change. It has no corresponding incentive to identify those costs that are decreasing or will not continue. Information asymmetries make it difficult for us to identify those future diminishing costs. Therefore, simply demonstrating that a new cost will be incurred—that is, a cost that was not incurred in the base year—is not a sufficient justification for introducing a step change. There is a risk that including such costs would upwardly bias the total opex forecast.

The test we apply is whether the step change is needed for the opex forecast to achieve the opex objectives in the NER.[58] Our starting position is that only circumstances that would change a business's fundamental opex requirements warrant the inclusion of a step change in the opex forecast.[59] Two typical examples are:

- a material change in the business's regulatory obligations
- a prudent and efficient capex/opex substitution opportunity.[60]

We may accept a step change if a material 'step up' or 'step down' in expenditure is required by a network business to comply prudently and efficiently with a new, binding regulatory obligation that is not reflected in the productivity growth forecast.[61] This does not include instances where a business has identified a different approach to comply with its existing regulatory obligations that may be more onerous, or where there is increasing compliance risks or costs the business must incur to comply with its regulatory obligations. Usually when a new regulatory obligation is imposed on a business, it will incur additional expenditure to comply. The business may be expected to continue incurring such costs associated with the new regulatory obligation into future regulatory control periods; hence, an increase in its opex forecast may be warranted.

We expect the business to provide evidence demonstrating the material impact the change of regulatory obligation has on its opex requirements, and robust cost–benefit analysis to demonstrate the proposed step change expenditure is prudent and efficient to meet the change in regulatory obligations.[62] We stated in the explanatory statement accompanying the Expenditure Assessment Guideline:[63]

> [Network services providers] will be expected to justify the cost of all step changes with clear economic analysis, including quantitative estimates of expected expenditure associated with viable options. We will also look for the [Network services providers] to justify the step change by reference to known

58 NER, cl. 6.5.6(a).

59 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

60 NER, cl. 6.5.6(e)(7).

61 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

62 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, pp. 51–52; AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

63 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

> cost drivers (for example, volumes of different types of works) if cost drivers are identifiable. If the obligation is not new, we would expect the costs of meeting that obligation to be included in revealed costs. We also consider it is efficient for [Network services providers] to take a prudent approach to managing risk against their level of compliance when they consider it appropriate (noting we will consider expected levels of compliance in determining efficient and prudent forecast expenditure).

By contrast, proposed opex projects designed to improve the operation of the business, which we consider as discretionary in the absence of any legal requirement, should be funded by base opex and trend components, together with any savings or increased revenue that they generate—rather than through a step change. Otherwise, the business would improperly benefit from a higher opex forecast and the efficiency gains.[64]

We may also accept a step change in circumstances where it is prudent and efficient for a network business to increase opex in order to reduce capital costs. We would typically expect such capex/opex trade-off step changes to be associated with replacement expenditure (or "repex").[65] The business should provide robust cost–benefit analysis to demonstrate clearly how increased opex would be more than offset by capex savings.[66]

In the absence of a change to regulatory obligations or a legitimate capex/opex trade-off opportunity, we would accept a step change under limited circumstances. We would consider whether the costs associated with the step change are unavoidable and material—such that base opex, trended forward by the forecast rate of change, would be insufficient for the business to recover its efficient and prudent costs. We would also consider whether the business would continue to incur the costs of a proposed step change in future regulatory control periods.

Category specific forecasts

A category specific forecast may be justified if, as a result of including a specific opex category in the base opex, total opex becomes so volatile that it undermines our assumption that total opex is relatively stable and follows a predictable path over time.

A category specific forecast is an amount we may allow to be included in the opex forecast for a particular year, which is not appropriate as a step change, nor for inclusion in base opex, but which we nevertheless consider meets the legal criteria for efficient expenditure in that year.

We may also use category specific forecasts to avoid inconsistency or double counting within our determination. We have typically included category specific forecasts for

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64 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

65 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 74.

66 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

debt raising costs and the demand management incentive allowance mechanism (DMIAM). In jurisdictions where GSL payments were historically included under category specific forecasts, we continue to do so. There are specific reasons for forecasting these categories separately from base opex. For example, we forecast debt raising costs separately to provide consistency with the forecast of the cost of debt in the rate of return building block of allowable revenue. For DMIAM, we forecast these costs separately because we fund them through a separate building block.

Absent such exceptions, we expect that base opex, trended forward by the rate of change, will allow the business to recover its prudent and efficient costs. This is a reasonable assumption given that the business has operated in the past with that level of opex, demonstrating that it is able to operate prudently and efficiently in meeting all its existing regulatory obligations, including its safety and reliability standards. We consider it is also reasonable to expect the same outcome looking forward with the increase provided through the trend growth in the base opex. Some costs may go up, and some costs may go down—despite potential volatility in the cost of certain individual opex activities, total opex is generally relatively stable over time. As we stated above in relation to step changes, a business has an incentive to inflate its total opex forecast by identifying new and increasing costs, but it does not have the same incentive to identify declining costs in its forecasts. Consequently, there is a risk that providing a category specific forecast for opex items identified by the business may upwardly bias the total opex forecast. By applying our revealed cost approach consistently and carefully scrutinising any further adjustments, we avoid this potential bias.

6.3.3 Interrelationships

In assessing SA Power Networks' total forecast opex we also took into account other components of its proposal that could inter-relate with our opex decision.[67] The matters we considered in this regard included:

- the impact of cost drivers that affect both forecast opex and forecast capex. For instance, forecast labour price growth affects forecast capex and the opex rate of change
- SA Power Networks' proposed step changes which have an upfront opex and capex investment, and subsequent efficiencies in opex and capex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block.

[67] When making revenue decisions under the NEL, we must specify the manner in which the constituent components of our decision relate to each other, and the manner in which we take account of these interrelationships: NEL, s. 16(1)(c).

6.4 Reasons for draft decision

Our draft decision is to include total forecast opex of $1472.9 million[68] ($2019–20) in SA Power Networks' revenue for the 2020–25 regulatory control period. Our alternative estimate is $78.1 million ($2019–20) or 5.0 per cent less than SA Power Networks' proposal of $1551.0 million[69] ($2019–20). We are satisfied our alternative estimate of total forecast opex for SA Power Networks reasonably reflects the opex criteria.[70]

Table 6.4 presents the components of our alternative estimate compared to SA Power Networks' proposal. The key differences between our alternative estimate of total forecast opex and SA Power Networks' proposal are:

- We have forecast output growth using our standard approach (using weights from all of our benchmarking models) rather than the average of the results from the two Cobb Douglas benchmarking models as proposed by SA Power Networks. Using our standard approach lowers forecast opex by 0.1 per cent each year. Our alternative estimate for output growth is $5.0 million ($2019–20) lower than SA Power Networks' proposed amount over the 2020–25 regulatory control period.
- We have forecast opex productivity growth of 0.5 per cent per annum reflecting the outcome of our recent opex productivity growth forecast review.[71] In comparison, SA Power Networks did not forecast productivity growth in its proposal, although it has indicated that it will include productivity growth of 0.5 per cent in its revised proposal.[72] This means our alternative estimate for opex productivity growth is $20.8 million ($2019–20) lower than SA Power Networks' proposed amount over the 2020–25 regulatory control period
- We have forecast labour price growth using the latest forecasts from Deloitte.[73] This is a change from our approach in previous determinations of averaging the Deloitte's and BIS Oxford Economics' forecasts, which SA Power Networks used in its proposal. This change in approach lowers SA Power Networks' forecast price growth in our alternative estimate by 0.4 per cent each year. Our alternative estimate for price growth is $16.0 million ($2019–20) lower than SA Power Networks' proposed amount over the 2020–25 regulatory control period.
- We have included $53.6 million ($2019–20) for prudent and efficient step changes over the 2020–25 regulatory control period in comparison to SA Power Networks' forecast of $75.1 million ($2019–20). Our alternative estimate for step changes is $21.5 million ($2019–20) lower than SA Power Networks' proposed amount over the 2020–25 regulatory control period.

68 Including debt raising costs.

69 Including debt raising costs.

70 NER, cl. 6.5.6(c).

71 AER, *Final decision - Forecasting productivity growth for electricity distributors*, March 2019, p. 9.

72 SA Power Networks, *Letter to AER – SA Power Networks Regulatory Proposal 2020–25*, 3 June 2019.

73 Deloitte Access Economics, *Labour price growth forecasts prepared for the AER*, 24 June 2019.

- Our alternative estimate of debt raising costs is $13.3 million ($2019–20) lower than what SA Power Networks proposed. We do not consider that the available evidence supports SA Power Networks' proposed allowance for debt raising costs.

Table 6.4 SA Power Networks' proposal and AER draft decision ($ million, 2019–20)

	SA Power Networks proposal	AER draft decision	Difference
Base opex	1381.0	1381.0	–
2018–19 to 2019–20 increment	18.0	16.6	–1.4
Output growth	30.6	25.6	–5.0
Price growth	25.7	9.7	–16.0
Productivity growth	–	–20.8	–20.8
Step changes	75.1	53.6	–21.5
Total opex (excluding debt raising costs)	**1530.4**	**1465.7**	**–64.7**
Debt raising costs	20.5	7.2	–13.3
Total opex (including debt raising costs)	**1551.0**	**1472.9**	**–78.1**

Source: SA Power Networks, *RIN 1 – Workbook 1 – Regulatory determination template 2020–21 to 2024–25*, February 2019; SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019; AER analysis.

Note: Numbers may not add up to total due to rounding.

We discuss the components of our alternative estimate below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

SA Power Networks proposed $276.2 million for its base year opex.[74] This matched its 2018–19 estimated opex and is consistent with the 2018–19 opex allowance in our 2015–20 final decision.[75] We consider that this is a relatively efficient forecast, as indicated by our benchmarking results, and we have used it to develop our alternative estimate.

74 SA Power Networks, *RIN 1 – Workbook 1 – Regulatory determination template 2020–21 to 2024–25*, February 2019; SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p.22.

75 SA Power Networks, *2020–25 Regulatory proposal – RIN 1 – Workbook 1 – Regulatory determination template 2020–25*, February 2019; AER analysis.

SA Power Networks' proposal uses 2018–19 as the base year. It submitted that this is the most suitable base year because it best reflects the future costs required to efficiently maintain and operate its network, incorporates the efficiency gains that will have been achieved to 30 June 2019 and is the most recent year for which actual audited data will be available at the time of the AER's final decision.[76] Further, it submitted that earlier years in the 2015–20 regulatory control period do not provide an adequate base for the 2020–25 regulatory control period due to a number of atypical factors. SA Power Networks also advised that while it does not yet have audited 2018–19 accounts, its estimated base year opex (taking into account actuals) remains largely consistent with the estimated base year opex in its proposal.[77]

A submission by South Australian Council of Social Service questioned whether 2018–19 is an appropriate base year. It also submitted that opex was increasing over the 2015–20 regulatory control period and noted SA Power Networks' decreasing productivity.[78]

As shown in Figure 6.1, SA Power Networks has underspent against our approved allowance in the first three years of the 2015–20 regulatory control period. For the last two years of the 2015–20 regulatory control period, while SA Power Networks' opex is forecast to increase, it is in line with our approved allowance. Further, for reasons discussed below, our benchmarking results suggest there is sufficient evidence that SA Power Networks' revealed opex over the periods 2006–17 and 2012–17 was relatively efficient. As a result, we are not making an efficiency adjustment and we consider that 2018–19 is an appropriate base year.

Once a decision is made that the business's revealed opex is efficient, it does not matter which year is chosen as the base year, as the combined effect of the opex forecast and EBSS would result in little impact on the total revenue allowance for the business. This is because higher (or lower) opex is counteracted by decreases (or increases) in the EBSS carryover. These two effects offset each other from a total revenue allowance perspective.

We have used a variety of economic benchmarking tools to test the efficiency of SA Power Networks' opex. Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service as a means of assessing their relative performance. Our annual benchmarking reports include information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of distribution businesses in the NEM.[79]

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76 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 22.

77 SA Power Networks, *Information request 057 – Q1,* 9 July 2019, p. 1.

78 South Australian Council of Social Service, *SACOSS submission in response to AER Issues Paper on the SAPN electricity determination 2020-25*, 10 May 2019, p. 3.

79 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018.

Our preferred approach is to benchmark a business's efficiency on the basis of its average efficiency over time (using a period-average efficiency score from our econometric and opex multilateral partial factor productivity (MPFP) models). We consider that this is a better approach than looking at the efficiency of a single year (such as the base year) as this recognises that opex is generally recurrent, but with some degree of year-to-year volatility.

Our benchmarking results show that SA Power Networks has consistently been amongst the most productive and efficient distributors in the NEM over the last eleven years. Our 2018 Annual Benchmarking Report shows that SA Power Networks:

- Was second[80] in 2016–17 amongst all regulated distributors in terms of multilateral total factor productivity (MTFP) which measures the relationship between total output and total input (i.e. capital assets and opex) and third[81] amongst all regulated distributors in terms of the opex multilateral partial factor productivity (MPFP) which measures the relationship between total output and opex (see Figure 6.4)
- Was amongst the top five of all regulated distributors in terms of opex efficiency when measured using our econometric models and opex MPFP over the periods 2006–17 and 2012–17[82]
- Performed very well for various total cost and cost category partial performance indicators (PPIs) over the four year period 2013–17. The exception is average emergency response spend per interruption against customer density where it was one of the poorer performers.[83]

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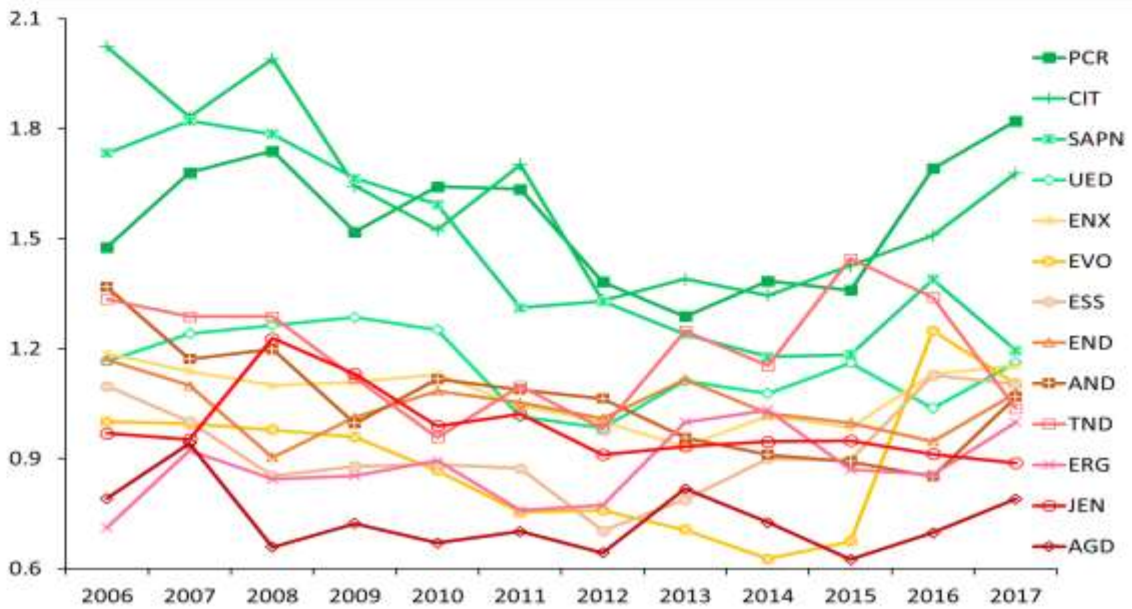
80 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018, p. 13.

81 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018. p. 16; Economic Insights, *2018 Annual Benchmarking Report – Data Update*, 8 October 2019. This update shows SA Power Networks third amongst network businesses for opex MPFP in 2017-18.

82 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018. pp. 31–32.

83 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018. pp. 34–42.

Figure 6.4 Opex multilateral partial factor productivity, 2006–2017



Source: AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018

While SA Power Networks has proven to be amongst the most productive and efficient distributors in the NEM over time, and as recently as 2016–17, its measured productivity has been in decline. SA Power Networks' productivity declined significantly from 2006–07 to 2013–14, which it attributed to rising input costs ranging from vegetation management, extreme weather (including GSL payments), new regulatory obligations to solar photovoltaics. While SA Power Networks experienced two consecutive years of productivity growth in 2014–15 and 2015–16, its productivity declined sharply in 2016–17. SA Power Networks again attributed this decline to increases in its costs of responding to abnormal storms and other weather events.[84] However, even with declining opex productivity, in 2016–17 SA Power Networks was still third amongst network businesses in the opex MPFP benchmarking.[85]

SA Power Networks' estimated opex in 2018–19 is $10.9 million (or 4.1 per cent) higher than 2017–18, and $6.3 million (or 2.3 per cent) higher than 2016–17, although estimated base opex is consistent with the opex allowance set by the AER. Despite this increasing opex, the benchmarking evidence suggests that over the periods 2006–17 and 2012–17 SA Power Networks was operating relatively efficiently and that there is no basis for us to make an efficiency adjustment to its base year opex.

84 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018. p. iv.

85 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018. p. 16. Economic Insights, *2018 Annual Benchmarking Report - Data Update,* 8 October 2019 shows SA Power Networks third amongst network businesses in 2017-18.

We will continue to monitor SA Power Networks' performance via our benchmarking. Future benchmarking results will incorporate the GSL step change (see section 0) impacting opex. This is expected to enhance the benchmarking comparison by removing GSL payments (that are currently higher than other businesses) from SA Power Networks' base opex (reflecting the changing GSL obligations that are more in line with other jurisdictions). Our future benchmarking results will also take into account the other step changes that we are including in our alternative estimate of opex for the draft decision. We also note that SA Power Networks' capitalisation policy may impact the comparability of the benchmarking results and that this is an area we will consider as a part of our ongoing benchmarking development program.

A number of submissions suggested that we examine specific cost categories. The SA Government was concerned that there appears to be a significant increase in forecast corporate costs from 2019–20 to 2020–21 (approximately $5 million or 6.6 per cent) followed by smaller increases in subsequent years.[86] Further information provided to us by SA Power Networks showed that a large proportion of the proposed increase in corporate costs is related to information technology costs.[87] These costs are proposed by SA Power Networks as opex step changes which are separately reviewed in section 6.4.3. SA Power Networks also stated that these increases incorporate the relevant rate of change that is applied to corporate (and all other) costs. We discuss rate of change further in section 6.4.2, but note that our alternative estimate of the rate of change is lower than SA Power Networks' proposal.

In relation to corporate costs, we also examined the total overheads PPIs included in our 2018 Annual Benchmarking Report. While this PPI reflects the sum of corporate and network overheads allocated to standard control services (capex and opex)[88] we observe that SA Power Networks was amongst the best performing distributors in this cost category partial benchmarking.[89]

Business SA[90] and the SA Wine Industry Association[91] also raised vegetation management costs and questioned why the recent and forecast ongoing drier conditions have not resulted in reductions in vegetation management costs. Our observation is that base year vegetation management opex is consistent with the costs in 2017–18 which is also consistent with the average costs over the five years to 2017–

86 Government of South Australia, *Submission to the Australian Energy Regulator on the SA Power Networks' Regulatory Proposal 2020-25*, 16 May 2019, p. 3.

87 SA Power Networks, *Information request 065 – Q5,* 17 July 2019, p. 5.

88 The use of total expenditure (i.e. including both capex and opex) allows better comparability when we benchmark overheads given the different capitalisation policies across the distribution businesses.

89 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018, pp. 41–42.

90 Business SA Chamber of Commerce and Industry South Australia, *Business SA submission to AER on SA Power Networks 2020-25 Regulatory Proposal*, May 2019, p. 8.

91 South Australian Wine Industry Association, *Submission in response to the Issue Paper on SA Power Networks' Regulatory Proposal for 2020-25*, 15 May 2019, p. 4.

18.[92] Over this period actual vegetation management costs have been variable and ranged from a low of $32.0 million ($2019–20) to a high of $50.3 million ($2019–20).

SA Power Networks also provided further information regarding increased costs that are driven by a higher volume of work that is related to the changing weather conditions it has experienced.[93] It also noted that changing weather conditions impact under half of its 40 vegetation management districts with the rest having a relatively consistent growth pattern. Further, that bushfire risk areas have an annual cutting cycle consistent with legislative requirements. This suggests that there are some vegetation management costs that are relatively constant but that variability is driven by those vegetation management districts which are impacted by changing weather conditions.

Our PPI benchmarking results for vegetation management support the notion that SA Power Networks is one of the lower cost electricity distributors in this category.[94]

In general, most submissions that commented on the base opex were relatively supportive of SA Power Networks' proposed base opex, noting SA Power Networks' relative efficiency as evidenced by the benchmarking results.

Our analysis shows that SA Power Networks has consistently been amongst the better performers in our benchmarking results and that it has operated within the opex allowance set by us, this is despite SA Power Networks' declining opex productivity trend. We have also examined the concerns raised in submissions on specific cost categories of SA Power Networks' base opex. For this draft decision we have used SA Power Networks base opex in our alternative estimate. We will examine SA Power Networks' actual 2018-19 opex that is included in its revised proposal, as well the cost categories, and update our benchmarking analysis for our final decision.

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[95]

SA Power Networks broadly applied our standard approach to forecasting the rate of change. It proposed:

- **Output growth:** to not apply the output weights from all four economic benchmarking models, as we did in our most recent determinations, but rather to apply the weights from the two Cobb Douglas econometric models (and not the translog or MPFP models).

92 SA Power Networks, *2020–25 Regulatory proposal – RIN 3 – Workbook 3 – CA - recast historical,* January 2019*;* SA Power Networks, *Information request 005*, 26 February 2019, AER analysis.

93 SA Power Networks, *Information request 065 – Q3,* 17 July 2019, p. 4.

94 AER, *Annual Benchmarking Report for electricity distribution network service*, November 2018, pp. 38-39.

95 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 22–24.

- **Price growth:** to adopt our input price weightings of 59.7 per cent labour and 40.3 per cent non-labour and the approach we applied in previous determinations for forecasting labour price growth using an average of Deloitte's and BIS Oxford Economics' forecasts.
- **Productivity growth:** to use zero productivity growth, although it has since advised that it would adopt our 0.5 per cent per year forecast in its revised proposal.[96]

The rate of change proposed by SA Power Networks contributes $56.4 million ($2019–20), or 3.6 per cent, to SA Power Networks' proposed total opex forecast of $1551.0 million. This equates to opex increasing by around 1.3 per cent each year.[97] We include a rate of change that increases opex by 0.3 per cent each year in our alternative estimate. The reasons for our forecast, and the difference compared to SA Power Networks' forecast, are set out below.

Forecast price growth

We have applied a real average annual price growth of 0.2 per cent to develop our alternative opex forecast. This increased our alternative estimate of total opex for the 2020–25 regulatory control period by $9.7 million ($2019–20). It compares to SA Power Networks' proposed average annual price growth of 0.6 per cent.[98]

Our real price growth forecast is a weighted average of forecast labour price growth and non-labour price growth:

- To forecast labour real price growth we have used the most up-to-date forecast of growth in the utilities wage price index (WPI) for South Australia as forecast by Deloitte.[99] SA Power Networks used an average of utilities WPI growth forecasts for South Australia from BIS Oxford Economics and Deloitte.[100] We used this approach in previous decisions. We discuss below our reasons for using only the forecasts from Deloitte in our alternative estimate, and why we did not average them with the forecasts from BIS Oxford Economics.
- Both we and SA Power Networks applied a forecast non-labour real price growth rate of zero.[101]

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96 SA Power Networks, *Letter to AER – SA Power Networks Regulatory Proposal 2020–25*, 3 June 2019.

97 SA Power Networks, *2020-25 Regulatory proposal – Supporting document 6.8 – Opex SEM Model 2020-25 RCP*, January 2019.

98 SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 31; SA Power Networks, *2020-25 Regulatory proposal – Supporting document 6.8 – Opex SEM Model 2020-25 RCP*, January 2019.

99 Deloitte, *Labour price growth forecasts*, 24 June 2019.

100 SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 32.

101 SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 32.

- We applied benchmark input price weights of 59.7 per cent and 40.3 per cent for labour and non-labour, respectively. These are the weights we use for our econometric modelling in our annual benchmarking report.[102] SA Power Networks applied the same input price weights.[103]

Consequently, the key difference between our real price growth forecasts and SA Power Networks' is that we only used forecasts from Deloitte, rather than an average of the real WPI growth forecasts from Deloitte and BIS Oxford Economics.

Deloitte's forecasts of utilities real WPI growth for South Australia reflect the best estimate of labour real price growth

There is a significant difference between the WPI growth forecasts provided by Deloitte, who we engaged, and those provided by BIS Oxford Economics, who was engaged by SA Power Networks (Table 6.5). From 2020–21, BIS Oxford Economics is forecasting annual wage growth to be around 1 percentage point higher than Deloitte.

Table 6.5 Forecast utilities WPI growth for South Australia, per cent

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25
Deloitte	0.6	0.6	0.4	0.4	0.3	0.5	0.4
BIS Oxford Economics	0.7	0.8	1.2	1.5	1.7	1.6	1.4

Source: Deloitte, *Labour Price Growth Forecasts*, 24 June 2019, p. xiii; SA Power Networks, 2020–2025 Regulatory proposal – Supporting document 6.6 – BIS Oxford Economics – *Utilities construction wage forecasts to 2024–25*, October 2018, p. 2.

A number of stakeholders questioned whether SA Power Networks' price growth forecasts were reasonable, given the subdued wage growth that has occurred in South Australia in recent years. For example:

- Our Consumer Challenge Panel (CCP14) noted that the businesses' labour price WPI forecasts are consistently higher than those forecast by Deloitte.[104] CCP14 considered we should seek to understand why the differences between respective consultants persist and whether the averaging approach is a robust methodology.[105]
- The South Australian Council of Social Service noted that observed wage growth is subdued and recommended that the reasons for the differences between the

[102] Economic Insight, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, p. 2.

[103] SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 31.

[104] CCP14, *Advice to the AER on the SA Power Networks' 2020–25 regulatory proposal*, 16 May 2019, p. 33.

[105] CCP14, *Advice to the AER on the SA Power Networks' 2020–25 regulatory proposal*, 16 May 2019, p. 33.

higher BIS Oxford Economics' forecasts and Deloitte's forecasts should be evaluated.[106]

- The Energy Project noted that it was surprised by the high labour price growth forecast by BIS Oxford Economics. Given the low wage growth across the economy it did not consider BIS Oxford Economics' forecasts were reasonable. It considered that Deloitte's labour price growth forecasts should be applied, not an average 'distorted' by what it regarded to be unreasonably high forecasts.[107]
- Business SA considered labour price growth forecasts should represent a fair judgement on what is a justified wage increase and not simply the average of consultant reports, 'particularly when those previous forecasts have been shown to be quite optimistic'.[108]
- The South Australian Wine Industry Association believed that, in the current economic climate, SA Power Networks should strive for restraint in labour costs just like all other businesses. It was concerned that the proposed labour price growth forecasts may not be in the long-term interests of customers.[109]

As noted above, our previous approach to forecasting labour price growth has been to use an average of the utilities industry real WPI growth forecasts for the relevant state provided by a consultant engaged by us (Deloitte) and the forecasts submitted by the network business (often BIS Oxford Economics). We adopted this approach after testing the accuracy of the forecasts from both consultants. We found, at that time, that an average of the two forecasts was closer to actual utilities WPI growth than either of the individual forecasts. However, we last did this in September 2012, for the period 2006 to 2011.[110] Since then, wage price growth has changed significantly. Given the concerns raised by stakeholders we have reassessed how well the consultants' WPI growth forecasts compare with actual WPI growth.

We have looked at 18 WPI growth forecast reports from Deloitte and 16 from BIS Oxford Economics. We took the Australian utilities real and nominal WPI growth forecasts from each of these reports for the years 2007 to 2018 and compared them to actual Australian real and nominal WPI growth for the electricity, gas, water and waste services (utilities) industry reported by the Australian Bureau of Statistics (ABS).[111] We

[106] SACOSS, *SACOSS submission in response to AER issues paper on the SAPN electricity determination 2020–2025*, 10 May 2019, pp. 11–12.

[107] Partnership of SA Financial Counsellors Association, The Energy Project and Uniting Communities, *Submission: Issues Paper – SA Power, Networks revenue determination 2020–2025*, 22 May 2019, p. 21.

[108] Business SA, *Business SA submission: to AER on SA Power Networks 2020–25 regulatory proposal (including tariff structure statement)*, May 2019, p. 10.

[109] South Australian Wine Industry Association, *Submission in response to the issue paper on SA Power Networks' regulatory proposal for 2020–25*, 15 May 2019, p. 4.

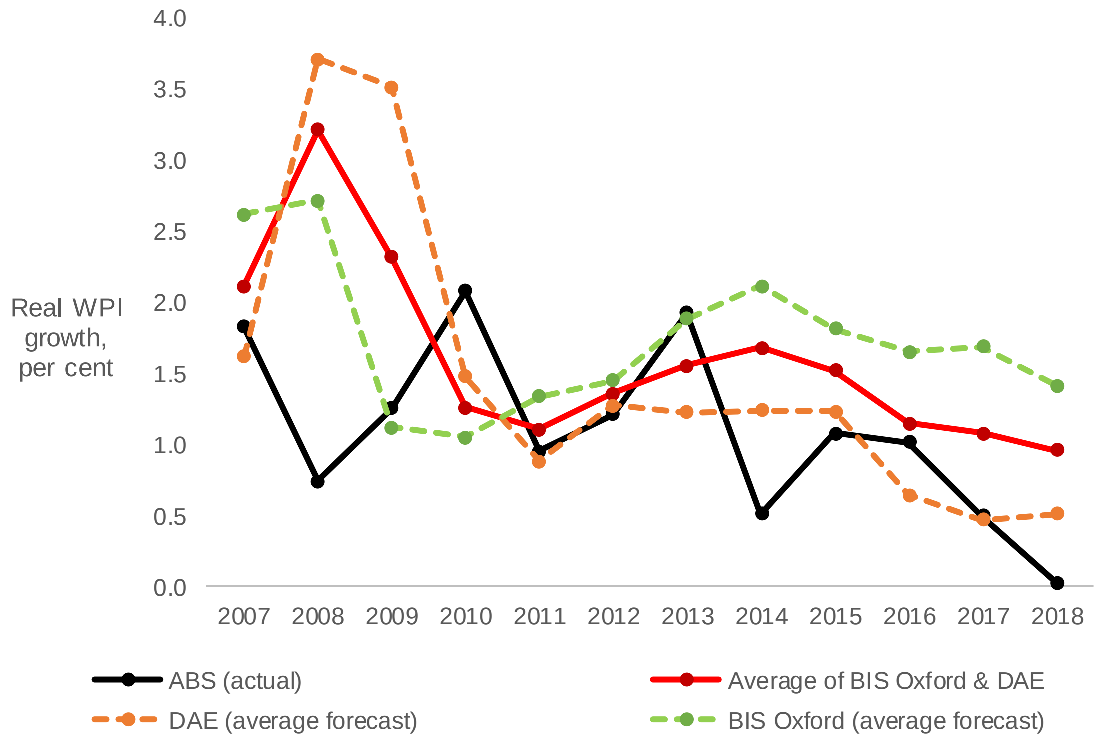
[110] AER, *Access arrangement draft decision, SPI Networks (Gas) Pty Ltd 2013–17, Part 3, Appendices*, September 2012, pp. 78–81.

[111] ABS, Catalogue number 6345.0, Wage price index, June 2019.

found that the forecasts from Deloitte were more accurate than the forecasts from BIS Oxford Economics.

In Figure 6.5, we present the average Australian utilities industry real WPI growth forecast for each year from Deloitte, BIS Oxford Economics and an average of the two. We also show actual utilities industry WPI growth as reported by the ABS. Since 2011, BIS Oxford Economics forecasts (the green dashed line) have been persistently at, or above, actual real WPI growth (the black line). Over the same period, Deloitte's forecasts (the orange line) have been closer to actual real WPI growth. This analysis is available in appendix A.

Figure 6.5 Real WPI growth—Australian utilities sector



Source: AER analysis.

We note that our 2012 analysis tested the accuracy of the two consultants' nominal WPI growth forecasts. However, we now use the real WPI growth forecasts and consider the accuracy of the real WPI growth forecasts is a more relevant consideration. Over the period from 2007 to 2018, Deloitte's real WPI growth forecasts had a mean error of 0.1, compared to BIS Oxford Economics mean error of 0.7. This indicates that over the sample period, Deloitte over forecast real WPI growth by only 0.1 percentage points, compared to 0.7 percentage points for BIS Oxford Economics. While the mean error is useful in that it shows whether a forecaster tends to over or under forecast, these results do not necessarily mean that Deloitte's forecasts are usually more accurate than BIS Oxford Economics'. This is because, within the mean error, positive and negative errors will cancel each other out.

Consequently, we also looked at the mean absolute errors. We found Deloitte had a lower mean absolute error of 0.5 percentage points, compared to 0.8 percentage points for BIS Oxford Economics. This shows that Deloitte's forecasts also tend to be closer to actual real WPI growth than BIS Oxford Economics'. It is also interesting to compare the mean errors of the consultants' forecasts with their mean absolute errors. The fact that Deloitte's mean error is significantly lower than its mean absolute errors shows that it didn't consistently over forecast or under forecast. However the fact that BIS Oxford Economics' mean error and mean absolute error were almost the same shows that it almost always over forecast.

We also analysed the accuracy of the consultants' nominal WPI growth forecasts. We found Deloitte had a mean error of 0.5 percentage points and a mean absolute error of 0.6 percentage points. BIS Oxford Economics had a mean error of 1.2 percentage points and a mean absolute error of 1.2 percentage points. This shows that both forecasters consistently over forecast on a nominal basis, with Deloitte over forecasting less than BIS Oxford Economics. We looked at Deloitte's CPI growth forecasts and found that it had over forecast CPI growth. Consequently Deloitte over forecast nominal WPI growth, while its real WPI growth forecasts have not shown any persistent over (or under) forecasting (as shown in Figure 6.5). We found that BIS Oxford Economics, however, persistently over forecast WPI growth on both a nominal and real basis.

We also analysed how well Deloitte and BIS Oxford Economics forecast real WPI growth at the "all industries" level (in comparison to the utilities level). We found Deloitte had a mean error of 0.0 percentage points and a mean absolute error of 0.6 percentage points. BIS Oxford Economics had a mean error of 0.3 percentage points and a mean absolute error of 0.9 percentage points. This shows that their forecasting performance was closer to each other at the "all industries" level than it was for the utilities industry. BIS Oxford Economics did not over forecast as much at the "all industries" level.

Based on this analysis, we now consider that Deloitte's utilities industry real WPI growth forecast, rather than BIS Oxford Economics', or an average of the two, better reflects actual Australian utilities real WPI growth.

We were unable to conduct similar analysis for the South Australian utilities industry specifically. The ABS does not publish utilities industry WPI index numbers for South Australia. In the absence of South Australian specific data, we consider the forecasting performance at the national level is indicative of the consultants' performance at the state level.

We have used our benchmark input price weights

We applied benchmark input price weights of 59.7 per cent and 40.3 per cent for labour and non-labour, respectively. These are the weights we use to compile our opex price index in our econometric modelling for our annual benchmarking report.[112]

Energy Consumers Australia, however, questioned whether our benchmark weights provide a reasonable forecast of price growth increases associated with wage growth. It stated that SA Power Networks' Regulatory Information Notice suggests that labour only comprises 41 per cent of total opex.[113]

We maintain the view that it is appropriate to use our benchmark input price weights, which represents an industry average, rather than firm-specific revealed weights. We have previously considered whether to use firm-specific revealed input price weights in our determination for AusNet Services for its 2016–20 regulatory control period.[114] We maintain the views expressed in that decision. In particular, using a firm's revealed input would remove the incentive for it to adopt a more efficient input mix. It would instead have an incentive to use more of the input that is forecast to increase in price more rapidly. Consequently, using a distributor's revealed input mix would not provide it with effective incentives in order to promote economic efficiency[115] and would not be in the long term interest of consumers.[116]

Forecast output growth

We have forecast average annual output growth of 0.6 per cent in developing our alternative opex forecast. It compares to SA Power Networks' proposed average annual output growth of 0.7 per cent.[117] This increases our alternative estimate over the 2020–25 regulatory control period of total opex by $25.6 million ($2019–20) instead of $30.6 million proposed by SA Power Networks.

SA Power Networks proposed that we change our current approach to forecasting output growth based on advice it received from NERA.[118] NERA recommended that the output weights be derived from an average of the results of the two Cobb Douglas

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112 Economic Insight, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, p. 2.

113 Dynamic Analysis, *Technical regulatory advice to the ECA review of South Australia Power Networks (SAPN) 2020-25 regulatory proposal*, May 2019, p. 31.

114 AER, *AusNet Services distribution determination 2016 to 2020: Final decision: Attachment 7*, May 2016, pp. 73–74.

115 NEL, s. 7A(3).

116 NEL, s. 7.

117 SA Power Networks, *2020-25 Regulatory proposal – Supporting document 6.8 – Opex SEM Model 2020-25 RCP*, January 2019.

118 SA Power Networks, 2020–25 *Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, pp. 29–31; SA Power Networks, *2020-2025 Regulatory proposal, Supporting document 6.5, NERA - Review of the AER's proposed output weightings*, December 2018.

econometric models. In contrast, our approach uses all four of our benchmarking models[119], namely:

- opex multilateral partial factor productivity (MPFP)
- Cobb Douglas stochastic frontier analysis (SFACD)
- Cobb Douglas least squares estimation (LSECD)
- Translog least squares estimation (LSETLG).

At a high level, NERA's concerns with our approach relate to:

- The methodology and transparency of the opex MPFP weights
- The view that it is not appropriate to use energy throughput in the opex MPFP model, particularly because it fails to take into account the impact of distributed energy resources
- The view that it is not appropriate to use the least squares translog models.

Adopting the approach recommended by NERA, SA Power Networks' forecast of average annual output growth is 0.7 per cent, which is 0.1 per cent higher each year compared to using our standard approach.

Economic Insights, engaged by us, reviewed NERA's report and outlined several areas of concern in relation to NERA's analysis and proposed approach.[120] We consider that Economic Insights' review of NERA's arguments is sound. We are satisfied that our current output forecasting approach remains appropriate and will continue to forecast output growth using all of our benchmarking models. Appendix B summarises the technical concerns raised by NERA about our approach and Economic Insight's response to each of the concerns.

We recognise that NERA raised a fair concern about whether energy throughput fully accounts for the impact of distributed energy resources and consider that it will likely be appropriate to review the output specification used in our benchmarking models. Currently, the energy throughput output variable captures changes in the amount energy delivered to customers over the distribution network as measured at the customer meter. It does not measure energy delivered into the distribution network via distributed energy resources, such as from residential roof-top solar panels. An increase in roof-top solar panels could potentially involve a substitution of different energy sources amongst the same customers without changing the total energy consumed or materially changing the existing network in terms of circuit length or maximum demand. However, a distributor may be required to incur higher opex and/or capital to manage the safety and reliability of its network. In this situation there could

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119 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/annual-benchmarking-report2018.

120 Economic Insights, *Review of NERA report on output weights*, 30 April 2019.

be a material increase in inputs without a corresponding increase in any or all of the output measures. Under these extreme circumstances, the existing output measures would not allow the distributor to recover prudent and efficient costs associated with a significant change to its operating environment. We acknowledge that more work will need to be done to properly assess this impact.

Our view is that any changes to the output forecasting approach should be made as part of a wider periodic review of economic benchmarking. Further, such a review will not be confined to just removing certain outputs—it will need to consider adding new outputs as well as removing any obsolete outputs to refine the forecasting approach. Such a review would also need to consider the data requirements for any new output specification.

In the meantime, to the extent that our output specification does not fully account for growing distributed energy resources, we will consider any necessary step changes. In particular, we have assessed SA Power Networks' proposed step change relating to LV management that is driven by increasing use of distributed energy resources in its network. See below on the LV management step change. It would be inappropriate to take into account distributed energy resources in our output specification via output growth, and provide step changes for it at the same time.

In terms of our current approach to forecast output growth, we have forecast our year-on-year output growth by:

- Calculating the output growth rates for four outputs (customer numbers, circuit line length, energy throughput, and maximum demand) based on the SA Power Networks' forecasts.
- Calculating four weighted average overall output growth rates using the specification and weights from four models presented in 2018 Annual Benchmarking Report – Data Update[121] (see Table 6.6).
- Averaging the four model specific weighted overall output growth rates.

We will publish our 2019 Annual Benchmarking Report in late November 2019. In our final decision, we will update our output growth rate forecasts to reflect the results in the 2019 Annual Benchmarking Report. Full details of our approach to forecasting output growth are set out in our opex model, which is available on our website.

121 Economic Insights, *2018 Annual Benchmarking Report – Data Update*, 8 October 2019 at: https://www.aer.gov.au/networks-pipelines/network-performance/annual-benchmarking-report-distribution-and-transmission-2018.

Table 6.6 Output specification and weights derived from economic benchmarking models

Output	MPFP	SFACD	LSECD	LSETLG
Customer numbers	31.0%	71.7%	68.7%	57.7%
Circuit length	29.0%	12.7%	10.8%	11.3%
Ratcheted maximum demand	28.0%	15.6%	20.5%	31.0%
Energy throughput	12.0%			

Source: AER analysis; Economic Insights, *2018 Annual Benchmarking Report – Data Update*, 8 October 2019.

Note: Numbers may not add up due to rounding.

Forecast productivity growth

SA Power Networks did not include any forecast productivity growth in its opex forecast.[122] In its proposal SA Power Networks noted the AER's review of productivity growth was occurring, and that while customers and stakeholders had suggested positive productivity growth should be considered, it did not consider this was justified taking into account the available evidence. After SA Power Networks submitted its proposal, we published the final decision for our opex productivity growth review. [123]

A number of stakeholder submissions stated that SA Power Networks' opex forecast should include forecast productivity growth.[124]

We have used the 0.5 per cent per year productivity growth forecast from our opex productivity growth review final decision in our alternative estimate. This reduces our alternative opex estimate by $20.8 million compared to SA Power Networks.

SA Power Networks has recently advised that it will adopt the 0.5 per cent per year opex productivity growth forecast in its revised proposal.[125]

122 SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – operating expenditure*, 31 January 2019, p.21; SA Power Networks, *2020-25 Regulatory proposal – Supporting document 6.8 – Opex SEM Model 2020-25 RCP*, January 2019.

123 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019.

124 Including submissions from Consumer Challenge Panel 14, South Australian Council of Social Service, Business SA submission, South Australian Wine Industry Association and Central Irrigation Trust.

125 SA Power Networks, *Letter to AER – SA Power Networks Regulatory Proposal 2020–25*, 3 June 2019.

6.4.3 Step changes

In developing our alternative estimate, we typically include step changes for cost drivers such as new regulatory obligations or efficient capex/opex trade-offs. As we explain in the Expenditure Assessment Guideline, we will include a step change if the efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost.[126]

SA Power Networks proposed six step changes totalling $75.1 million ($2019–20) or 4.9 per cent of its proposed total opex forecast.[127] These are shown in Table 6.7 along with our draft decision, which is to approve step changes totalling $53.6 million ($2019–20).

Table 6.7 SA Power Networks proposed step changes and our draft decision ($ million, 2019–20)

Step change	SA Power Networks proposed step changes	AER draft decision	Difference
Cable and conductor minor repairs	68.2	49.7	–18.5
Critical infrastructure compliance	12.1	12.1	-
Cloud transition—cloud hosting	7.2	7.2	-
Cloud transition—work scheduling	3.8	3.8	-
LV management future networks	3.8	3.8	-
GSL reliability payments	–19.9	–23.0	–3.1
Total	**75.1**	**53.6**	**-21.5**

Source: SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating Expenditure*; AER analysis.
Note: Numbers may not add up to total due to rounding.

The following sections set out the reasons for our draft decision, including the alternative estimates we have developed for the cable and conductor minor repairs and GSL reliability payments step changes.

Cable and conductor minor repairs

SA Power Networks proposed a $68.2 million ($2019–20) step change for the reclassification of cable and conductor minor repair costs from capex to opex. It

[126] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.
[127] SA Power Networks, 2020–25 *Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 23.

applied a corresponding reduction to its capex forecast of $69.9 million ($2019–20).[128] We are satisfied that it is appropriate to treat this expenditure as opex, rather than repex, but we have included only $49.7 million ($2019–20) in our alternative opex estimate. This is $18.4 million ($2019–20) less than the $68.2 million ($2019–20) proposed by SA Power Networks for the reasons set out below. It is also consistent with the advice we received from Energy Market Consulting associates (EMCa).[129]

Table 6.8 Cable and conductor minor repair step change ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	14.2	13.5	13.5	13.5	13.5	**68.2**
AER draft decision	9.9	9.9	9.9	9.9	9.9	**49.7**
Difference	**–4.3**	**–3.5**	**–3.5**	**–3.5**	**–3.5**	**–18.4**

Source: SA Power Networks, *2020–25 Regulatory proposal—Attachment 6—Operating expenditure*, 31 January 2019, p. 23; AER analysis.

Note: Numbers may not add up to total due to rounding.

SA Power Networks proposed reclassifying cable and conductor minor repair costs as opex, rather than capex, because it considered doing so better reflects the nature of the expenditure.[130] SA Power Networks stated that cable and conductor minor repair costs cover repairs:

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

SA Power Networks also stated that the proposed reclassification would help to address potential intergenerational inequities that could be caused by continuing to treat this type of expenditure as capex.

SA Power Networks' proposed step change is based on its actual/estimated cable and conductor expenditure for the current regulatory control period. It forecast total cable and conductor expenditure to be equal to its historical average expenditure between 2014–15 and 2019–20. It used estimates for 2018–19 and 2019–20, which were higher than the expenditure it incurred in previous years (Figure 6.6). It then allocated total cable and conductor expenditure between opex and capex based on its actual expenditure for 2017–18 under its new allocation approach.

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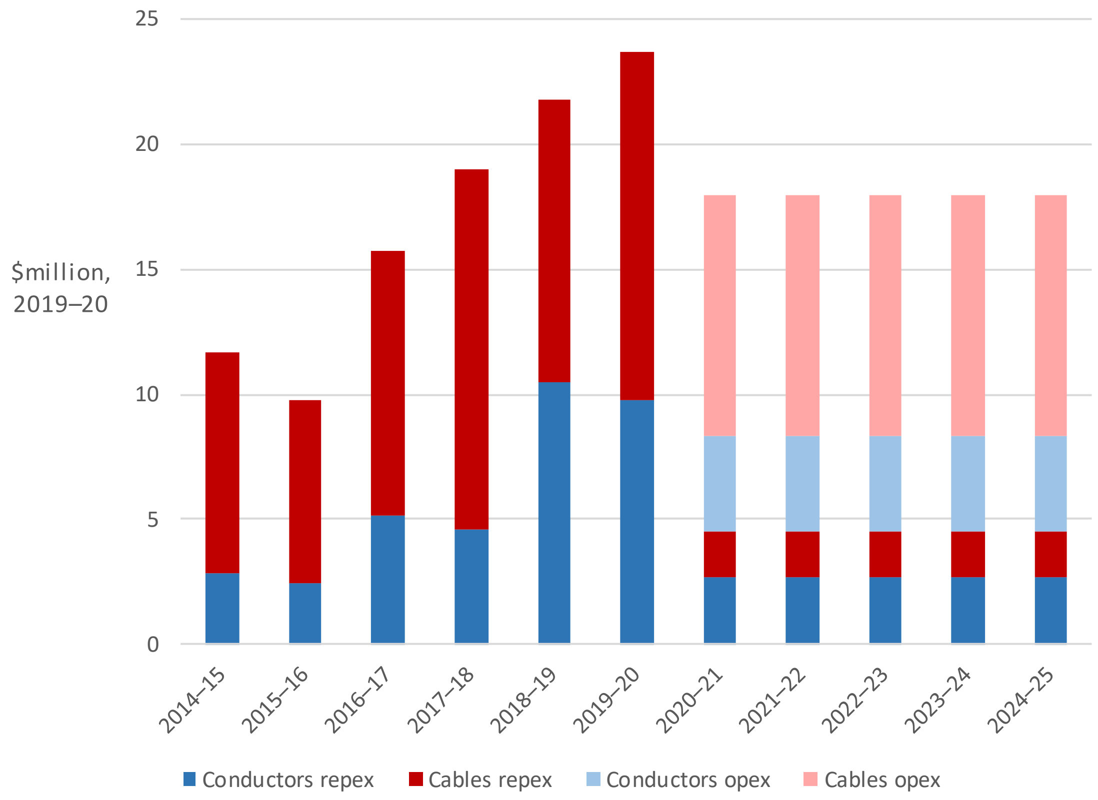
128 SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 26.

129 EMCa, *SAPN Revenue Proposal 2020–25: Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 50–64.

130 SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 26.

Figure 6.6 Historical and proposed cable and conductor repair expenditure ($ million, 2019–20)



Source: SA Power Networks, *Information request 019*, 8 May 2019; EMCa, *SAPN Revenue Proposal 2020—25: Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 53; AER analysis.

EMCa (engaged by us) reviewed the proposed cable and conductor repairs step change and considered that the proposed treatment is consistent with what it typically observes in other distributors. It found that the repair costs that SA Power Networks proposed to treat as opex were to replace minor sections of conductor or cable that would not extend the life of the cable or conductor being repaired. EMCa considered that, because the driver for the repairs is to address a current or imminent failure, it was reasonable to treat these minor repairs as opex.[131]

We also reviewed the nature of the repairs that SA Power Networks proposed to treat as opex. We reviewed the repairs that SA Power Networks undertook over the period 2015–16 to 2017–18 that it would have treated as opex under its proposed classification approach. We also looked at the average length of cable or conductor that was replaced for these types of repairs. We are satisfied that these represent minor repairs that would not extend the life of the cable or conductor being repaired.

131 EMCa, *SAPN Revenue Proposal 2020–25: Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 59.

Further, SA Power Networks' proposed treatment of cable and conductor expenditure is also consistent with its existing capitalisation policy.[132]

Based on our own analysis, and EMCa's advice, we are satisfied that SA Power Networks' proposal to treat cable and conductor minor repairs as opex is reasonable.

SA Power Networks also stated that the proposed reclassification would help to address potential intergenerational inequities that could be caused by continuing to treat this type of expenditure as capex. We did not consider it was not necessary to explicitly consider this point. Instead we have examined the nature of the expenditure to determine if the reclassification is appropriate.

However, we are not satisfied that the magnitude of the step change proposed by SA Power Networks reasonably reflects the efficient cost of a prudent firm. This is consistent with EMCa's view. SA Power Networks provided EMCa with an updated estimate of cable and conductor repair expenditure for 2018–19. This reflected actual expenditure to date, as at the beginning of June 2019. This updated estimate of $19.0 million ($2019–20) was lower than the estimate of $21.5 million ($2019–20) that SA Power networks used to forecast the step change. EMCa considered that an average of actual expenditure from 2014–15 to 2018–19, using this revised estimate, reasonably reflects the total expenditure SA Power Networks will require for minor cable and conductor repair.[133]

To allocate the total expenditure between opex and capex, EMCa considered the opex/capex ratio in the revised estimate for 2018–19 was an appropriate basis. This approach is consistent with the approach SA Power Networks used for its proposal where it used the ratio from the most recent year of actual expenditure (2017–18). On this basis, EMCa forecast an opex step change of $9.9 million ($2019–20) per year, or $49.5 million ($2019–20) over the 2020–25 regulatory control period.[134] This is lower than SA Power networks' proposal of $68.2 million ($2019–20).[135]

We conducted our own review of the efficiency of SA Power Networks' proposed step change. This included analysis of the cable and conductor volumes and unit rates reflected in SA Power Networks' proposal. We compared the unit rates (opex per fault/defect) implicit in SA Power Networks' proposal to the historic unit rates over the period 2015–16 to 2017–18. We have presented both the proposed and historic unit rates and volumes in Table 6.9. We found that SA Power Networks' forecast unit rates

132 SA Power Networks, *2020–2025 Regulatory proposal: Supporting document 18.21: Accounting Practice & Guidelines*, January 2019.

133 EMCa, *SAPN Revenue Proposal 2020–25: Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 61–62.

134 EMCa, *SAPN Revenue Proposal 2020–25: Review of aspects of SA Power Networks' capital expenditure*, September 2019, pp. 61–62.

135 SA Power Networks, *2020–2025 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 23.

for underground cables were higher than its historic unit rates. Forecast volumes for underground cables were similar to historical volumes. For overhead conductors, however, forecast volumes were higher than historic volumes, while forecast unit rates are similar to the historical rates.

Table 6.9 Proposed and historical volumes and unit rates for cables and conductors

	Historic average volume, no.	Historic average unit rate, S2019–20	Proposed volume, no.	Proposed unit rate, S2019–20
Underground cables, distribution defects	5.7	$23 684	5.6	$28 897
Underground cables, fault maintenance	1576.7	$4 413	1546.0	$6 211
Overhead conductors, distribution defects	79.7	$9 755	92.4	$9 491
Overhead conductors, fault maintenance	1446.3	$1 737	1677.3	$1 789

Source: SA Power Networks, *Information request 039 – Q47*, 3 June 2019; SA Power Networks, *Information request 058 – Q9*, 2 July 2019; AER analysis.

We found that forecasting the step change based on historical average volumes and unit rates (using actuals from the period 2015–16 to 2017–18) reduces the proposed step change to $51.9 million ($2019–20). We consider that this analysis, while using a different approach, supports EMCa's conclusion.

Based on EMCa's analysis, and our own, we consider that SA Power Networks' proposal overstates the efficient opex required by a prudent operator. We have included an opex step change of $49.7 million ($2019–20) in our alternative estimate. We have calculated this amount using the approach proposed by EMCa, converted to real 2019–20 dollars using the inflation figures in our opex model.

We note that typically we would treat a change in capitalisation policy as a base opex adjustment rather than a step change. In this instance we have treated it as a step change because this was the basis on which SA Power Networks proposed it.

Critical infrastructure compliance

SA Power Networks proposed a $12.1 million ($2019–20) step change for critical infrastructure compliance.[136] We are satisfied that this step change is required to meet new obligations that SA Power Networks faces and that the expenditure is efficient. We expect SA Power Networks to update its final cost estimate for critical infrastructure

136 SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating expenditure*, 31 January 2019, pp. 23, 27–28.

compliance in its revised proposal to reflect the outcome of a competitive tender currently underway and any further requirements from the relevant Commonwealth authorities.

Table 6.10 Critical infrastructure compliance step change ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	2.4	2.4	2.4	2.4	2.4	**12.1**
AER draft decision	2.4	2.4	2.4	2.4	2.4	**12.1**
Difference	–	–	–	–	–	–

Source: SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating Expenditure*, 31 January 2019, p. 23; AER analysis.

Note: Numbers may not add up to total due to rounding.

The proposed step change reflects new regulatory obligations imposed on SA Power Networks stemming from new requirements under the *Security of Critical Infrastructure Act 2018,* and other obligations imposed by the Commonwealth, to address national security risks associated with critical infrastructure.[137]

In our assessment we took into account confidential information provided by SA Power Networks and relevant Commonwealth authorities related to these new Commonwealth obligations. Confidential Appendix C sets out these specific new obligations, SA Power Networks' current non-compliance with some of these new obligations and the supporting confidential information we have relied on in our assessment.

We consider that this proposal meets the Expenditure Assessment Guideline's expectations for a step change associated new and major regulatory obligations.[138] These critical infrastructure system obligations are new 'regulatory obligations or requirements' as defined in the National Electricity Law (NEL)[139] and are associated with the provision of standard control services. These obligations impose a major shift in the way SA Power Networks must operate and control its network. The driver for this step change is out of the distributor’s control. These obligations are expected to have a major impact as they require SA Power Networks to address its current non-compliance as well as to comply fully with the new obligations during the next regulatory control period. We are also satisfied that the necessary changes to achieve

137 SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 27.

138 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, pp. 51–55; AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

139 NEL, s. 2D.

compliance have not been implemented and are therefore not accounted for in the base opex. Given this, we consider this step change is prudent.

SA Power Networks undertook a business case to evaluate the viability, costs and benefits of different options to determine the most efficient and prudent outcome for its customers. We examined confidential information provided by SA Power Networks in relation to these options (see confidential Appendix C). This included that SA Power Networks is currently actively testing the market through a competitive tender for services that will enable it to meet the new requirements.

We are of the view that SA Power Networks has systematically identified the impacts related to its new regulatory obligations and carefully assessed its options. Its approach to seeking the most efficient and least cost option, including by putting in place a competitive tender to secure services to meet the new requirements, appears prudent and efficient. We expect SA Power Networks to update its forecast in its revised proposal following the results of the competitive tender. We also expect SA Power Networks to update its forecast to reflect any agreement reached with the Commonwealth on other aspects of the proposed step change.

Cloud transition—cloud hosting

SA Power Networks proposed a $7.2 million ($2019–20) step change for cloud hosting.[140] We have included this step change for cloud hosting in our alternative estimate as we consider the capex/opex trade-off results in forecast expenditure that is prudent and efficient.

Table 6.11 Cloud transition—hosting step change ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	1.0	1.2	1.6	1.7	1.8	**7.2**
AER draft decision	1.0	1.2	1.6	1.7	1.8	**7.2**
Difference	–	–	–	–	–	–

Source: SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating Expenditure*, 31 January 2019, p. 23; AER analysis.

Note: Numbers may not add up to total due to rounding.

SA Power Networks proposed this $7.2 million ($2019–20) step change as a capex/opex trade-off. This increase in opex is associated with a $7.8 million ($2019–20) reduction in SA Power Networks' forecast recurrent capex (i.e. it is not included in

[140] SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 23.

the current capex forecast).[141] SA Power Networks submitted that this opex substitution reduced ongoing capital investment costs associated with updating and replacement of the related Information and Communication Technology (ICT) hardware.

The proposed step change involves connecting SA Power Networks' private cloud hosting services (provided by two third-party data centres) with external cloud hosting services to form a hybrid cloud.[142] The external cloud hosting services incur a subscription based operating cost.

SA Power Networks stated that its proposed move to a cloud based service is consistent with the broad changes in the ICT sector.[143] This trend has led to an increasing number of software applications being provided on a Software-as-a-Service (SaaS) model that uses the public cloud.[144] This trend is reinforced within SA Power Networks where a number of its ICT applications will only be available via SaaS after their next product upgrade early in the 2020–25 regulatory control period. The proposed move to a cloud based services is also consistent with the recommendations Nous Group provided to us as part of our 2015–20 final decision for SA Power Networks.[145]

In its business case, SA Power Networks noted that it had undertaken a Hosting Strategy review to consider appropriate hosting solutions. The various scenarios considered were put through preliminary assessments before options were explored in the business case with detailed cost modelling and analysis.[146]

Three options were considered for hosting services as a part of the IT Infrastructure Refresh business case, with option 2 being the preferred option:

- Option 1 – business as usual, retaining the two third party data centres but transitioning to SaaS for any applications where the vendor will no longer provide an on premise solution

141 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 25.

142 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 6.1 – IT Infrastructure Refresh Business Case*, January 2019, p. 21. A hybrid cloud is cloud infrastructure that involves a composition of two or more distinct cloud infrastructures (private, community or public) that remain unique entities but are bound together by standardised or proprietary technology that enables data and application portability.

143 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 6.1 – IT Infrastructure Refresh Business Case*, January 2019, pp. 11–12.

144 Cloud infrastructure provisioned for open use by the general public and existing on the premises of the cloud provider.

145 AER, *Final Decision – SA Power Networks determination 2015–20 – Attachment 6 – Capital expenditure,* October 2015, pp. 120–121; Nous Group, *South Australian Power Network's ICT expenditure 2015–20*, 9 July 2015, pp. 16, 19.

146 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 6.1 – IT Infrastructure Refresh Business Case*, January 2019, p. 20.

- Option 2 - a ‘measured move’ to the cloud, connecting SA Power Networks’ two third party data centres to external cloud hosting solutions to form a hybrid cloud
- Option 3 – aggressive move to the cloud, creates a hybrid cloud deployment based on a single data centre connected with external cloud services.[147]

We consider SA Power Networks did a thorough assessment of its ICT environment and assessed different hosting service options carefully to enable it to maintain its network and manage its outages effectively. It also demonstrated that it took a thorough approach to forecasting the relevant costs for this step change. It provided justifications for its modelling assumptions.[148] In determining the forecast, it utilised a mix of revealed costs, list prices and costs provided by vendors in responses to requests for quote. These costs included the application of historically applied discounts and a number of reasonably assumed discounts in the future. SA Power Networks’ initial costings were obtained using publicly available information in 2017. In early 2018, it also requested market quotes that firmed up its final projected costings. We are satisfied that SA Power Networks used the best available information.

The preferred option and proposed step change is a capex/opex trade-off and results in the lowest total expenditure of the options examined.[149] SA Power Networks proposed a corresponding reduction to its capex to support the underlying proposition that the substitution is efficient. We have confirmed that none of the foregone capex (related to what would have otherwise been spent on ongoing upgrades for the enterprise system) is included in the forecast for the 2020–25 regulatory control period. We are satisfied that SA Power Networks demonstrated the case for an efficient capex/opex trade-off in this step change.

As noted above, this step change is part of SA Power Networks’ broader IT Infrastructure Refresh business case (capex). Our acceptance of this step change is also supported by EMCa's (engaged by us) analysis of the capex component of this project.[150] It is of the view that the measured move to cloud model (option 2) is a prudent and appropriate IT strategy for the next regulatory control period.[151] It considers that the risk profile of this project is appropriately stated and mitigated. See Attachment 5 for the related capex assessment.

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147 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 6.1 – IT Infrastructure Refresh Business Case,* January 2019, p. 21.

148 SA Power Networks*, Information response 049,* 20 June 2019.

149 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 6.1 – IT Infrastructure Refresh Business Case*, January 2019, p. 46.

150 EMCa, *SAPN Revenue Proposal 2020–25, Review of aspects of SA Power Networks’ capital expenditure*, September 2019, pp. 34–35.

151 This is the “managed move” to a hybrid cloud model in SA Power Networks’ IT Infrastructure Refresh business case (in June 2017 dollars) with a proposed capex of $28.5 million and a $6.9 million opex step change.

Cloud transition—work scheduling

SA Power Networks proposed a $3.8 million ($2019–20) step change for cloud work scheduling.[152] We have included this step change for cloud work scheduling in our alternative estimate as we consider the capex/opex trade-off results in forecast expenditure that is prudent and efficient.

Table 6.12 Cloud transition—work scheduling step change ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	0.8	0.8	0.8	0.8	0.8	**3.8**
AER draft decision	0.8	0.8	0.8	0.8	0.8	**3.8**
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source: SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating Expenditure*, 31 January 2019, p. 23; AER analysis.

Note: Numbers may not add up to total due to rounding.

SA Power Networks proposed this $3.8 million ($2019–20) step change as a capex/opex trade-off. This opex increase is associated with a $3.8 million ($2019–20) reduction in SA Power Networks' forecast recurrent capex (i.e. not included in the current capex forecast).[153] The proposed step change is to replace the enterprise system for field work scheduling and management with a cloud based service.

SA Power Networks stated that the move to a cloud based service is consistent with its digital strategy and the broad changes in the ICT sector.[154] The current enterprise system is reaching its end of life, with primary and extended support expiring in December 2020. SA Power Networks' proposed move to a cloud based work scheduling and management is also consistent with the recommendations Nous Group provided to us as part of our 2015–20 final decision for SA Power Networks.[155]

In its business case, SA Power Networks undertook an options assessment to determine an optimal and cost-effective approach to manage its IT applications portfolio over the 2020–2025 regulatory control period.[156] It considered two options which both included a step change in opex ($3.8 million ($2019–20)) for moving to a

[152] SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 23.

[153] SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 26.

[154] SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 25.

[155] See footnote 148.

[156] SA Power Networks, *2020–25 Regulatory proposal – Supporting document 6.2 – IT applications refresh business case*, January 2019, pp. 27–44.

cloud based field work scheduling and management system given the end of life issues with its current system. The option with the lower overall total expenditure was chosen.

SA Power Networks explained that it undertook a desktop assessment of the work scheduling and mobility options it identified and how well these met its mandatory business requirements. This was done against evaluation criteria related to cost, strategic alignment, resource requirement and implementation timeframes. This analysis showed that the move to Click Field Service Edge (FSE) software would best meet user requirements, had a lower overall cost and best met resource and timeframe requirements.[157]

Since SA Power Networks prepared its business case, the timelines for extended support of its current system have moved to beyond the end of 2020. The additional information provided by SA Power Networks showed that, while the extension provided some flexibility, the preferred option would still be more cost effective and would result in a more strategic transition.[158]

We consider that SA Power Networks provided evidence that it reviewed its options appropriately to arrive at an effective work scheduling system. The preferred option to move to the Click FSE cloud based service was supported by feedback from similar distributors in site visits that confirmed the more limited functionality of the non-preferred option. In general, we accept that the forecasts are based on the best information available. It also demonstrated that its preferred option is cost effective.[159]

The preferred option and proposed step change is a capex/opex trade-off and results in the lowest total expenditure of the options examined.[160] SA Power Networks proposed a corresponding reduction to its capex to support the underlying proposition that the substitution is efficient. We have confirmed that none of the foregone capex (related to what would have otherwise been spent on ongoing upgrades for the enterprise system) is included in the forecast for the 2020–25 regulatory control period. We are satisfied that SA Power Networks demonstrated the case for an efficient capex/opex trade-off in this step change.

As noted above, this step change is part of SA Power Networks' broader IT Application Refresh business case (capex). Our acceptance of this step change is also supported by EMCa's (engaged by us) analysis of the capex component of this project. It is of the

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157 SA Power Networks, *Information response 048,* 13 June 2019.

158 SA Power Networks, *Information response 048*, 13 June 2019.

159 SA Power Networks, *Information response 048,* 13 June 2019.

160 SA Power Networks, *2020-25 Regulatory proposal – Supporting document 6.2 – IT Applications Refresh Business Case*, January 2019, p. 5 and Appendix B.

view that SA Power Networks' preferred option[161] represents a prudent approach with an efficient cost.[162] See Attachment 5 for the related capex assessment.

LV management

SA Power Networks proposed a $3.8 million ($2019–20) step change for LV management.[163] On balance we are satisfied that this step change is prudent and efficient expenditure to manage high voltage conditions on low voltage feeders and other constraints on the network arising from distributed energy resources (DER).[164] Reflecting this, we have included this step change in our alternative estimate.

Table 6.13 LV Management step change ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	–	0.4	0.9	1.1	1.3	**3.8**
AER draft decision	–	0.4	0.9	1.1	1.3	**3.8**
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source: SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating Expenditure*, 31 January 2019, p. 23; AER analysis.

Note: Numbers may not add up to total due to rounding.

The proposed step change is part of SA Power Networks' overall DER management program to develop new operational systems and business processes to manage the integration of solar, battery storage and virtual power plants (VPPs) into its distribution network.[165] The LV management program is predominantly capex totalling $31.8 million but has a related $3.8 million ongoing opex over the 2020–25 regulatory control period.[166]

161 This is option 2 in SA Power Networks' IT Applications Refresh business case with a proposed capex of $69.8 million and a $3.6 million opex step change (in June 2017 dollars) for moving to a cloud based work scheduling using a risk-based approach.

162 EMCa, *SAPN Revenue Proposal 2020–25, Review of aspects of SA Power Networks' capital expenditure*, September 2019, p. 34.

163 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 23.

164 Distributed Energy Resources (DER) commonly refers to solar PV (photovoltaic), storage, electric vehicles, and other consumer appliances that are capable of responding to demand or pricing signals. Increasing DER penetration represents a change in the way that consumers interact with electricity networks and the demands that it places on networks. DER management expenditure is the expenditure which seeks to manage the growing effects of higher penetration of DER on the network, in particular the effects of solar PV and the impact on distributor's ability to control voltage.

165 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 23.

166 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 5.18 – LV Management Business Case*, 25 January 2019, pp. 13–14.

We have assessed the capex and opex forecasts, being inter-related and inter-dependent, jointly for this program and refer to it as the Distribution System Operator (DSO) transition program.[167] Attachment 5 shows the overarching assessment and capex view. In summary, we consider that SA Power Networks has demonstrated the need and that the capex of the program is the least-cost solution. It has shown evidence of a potential voltage non-compliance issue.[168] It has also developed a business case and a cost-benefit analysis.[169] There is wide support from stakeholders for the program.[170] On balance we find this proposal by SA Power Networks to be reasonable and prudent based on the best current information.

In this section we summarise the key considerations in reviewing the components of this opex step change. The proposed step change[171] is for:

- Establishing visibility of LV network hosting capacity ($2.6 million) through procuring data from competitive smart meter providers and other third parties. Other costs relate to the set-up, ongoing development and maintenance of the application programming interface that will enable the monitoring. This is argued by SA Power Networks as an efficient capex/opex trade-off as it avoids procuring its own monitoring devices.
- Putting in place a DER register ($0.5 million); including staff and systems associated with the operation of a DER register, which SA Power Networks stated is now required after a 2018 rule change.
- Developing a LV hosting capacity model ($0.5 million); including staff and other costs associated with maintaining LV network topology and hosting capacity limits.
- Implementing open interfaces to publish dynamic export limits to customers and DER aggregators ($0.2 million); including operating the systems associated with LV

167 This is to avoid the confusion between this LV management program with the LV monitoring program proposed by SA Power Networks.

168 SA Power Networks, *Information request 020 - Q4, 5*, 1 May 2019, p. 6.

169 SA Power Networks, *2020–25 Regulatory proposal – Supporting document 5.21 – EA Tech – LV management strategy*, 18 December 2018; SA Power Networks, *2020–25 Regulatory proposal – Supporting document 5.22.1 – EA Tech – LV management strategy AN 1 DER hosting capacity assessment*, 23 November 2018; SA Power Networks, *2020–25 Regulatory proposal – Supporting document 5.22.2 – EA Tech - LV management strategy AN 2 development of the transform model*, 23 November 2018; SA Power Networks, *2020-25 Regulatory proposal – Supporting document 5.18 – LV Management Business Case,* 25 January 2019.

170 SA Minister for Energy and Mining, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019, p. 1; CSIRO, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; Clean Energy Council, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; GreenSync, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; Redback Technologies, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; Tesla, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019; Total Environment Centre, *Submission on SA Power Networks regulatory proposal 2020–25*, May 2019. See also footnotes 29–31.

171 SA Power Networks, *2020–25 Regulatory proposal – Attachment 6 – Operating expenditure*, 31 January 2019, p. 24–25; SA Power Networks, *2020–25 Regulatory proposal – Supporting document 5.18 – LV Management Business Case*, 25 January 2019, p. 14.

network constraint calculation and ongoing publication of dynamic export limits to small embedded generators, aggregators and Virtual Power Plant operators.

The above expenditure is opex in nature and is directed primarily to putting in place and maintaining ongoing systems to better manage voltage non-compliance issues impacting on the network predominantly due to solar PV.[172]

Typically we would not provide a step change in opex to operate and maintain a new asset. The standard approach of allowing opex increases in line with the output growth forecast would normally compensate a prudent operator for operating and maintaining a network not faced with an unusual operating environment. However with DER, SA Power Networks appears to be facing significant demands to manage its network and address its customers' needs that, if not addressed properly, might lead to voltage non-compliance issues. It is arguable that the opex output growth forecast may not allow adequate opex for this purpose.[173] A fuller discussion of this issue is found is below. On this basis, we consider it is appropriate to allow an opex step change in this case.

We reviewed the details of the cost build-up of each of the above key components to establish whether the magnitude of the opex proposed is efficient. SA Power Networks and its advisers, KPMG, provided information on the cost build-up of each of the program's components. The costing for the proposed opex was based on, where appropriate, KPMG's analysis, third party quotes and standard market rates (that have been market tested for external contractors).[174] The information showed that the estimated opex for the program had been refined down from around $28 million to about $4 million.[175] We have not identified any unexplainable or unnecessary costs included in this cost estimate and consider it is likely to be the least-cost option based on best current information.

Overall, we accept this opex step change given that:

- There is a likelihood that, at least in the short term, the output growth forecast may not fully compensate for the higher opex required to address DER
- Based on the information available, the capex component of the LV Management program is considered to be the least-cost solution
- Our analysis of the proposed opex suggests it is the least-cost option.

[172] Photovoltaic (PV) cells convert visible light into electricity.

[173] See below for a related discussion on the concerns about energy throughput and the impact of DER, including whether it may be appropriate to reconsider the output specification used in our benchmarking models.

[174] SA Power Networks – *2020–25 Regulatory proposal – Supporting document 5.18 – LV Management Business Case*, 25 January 2019, p. 15.

[175] SA Power Networks, *2020–25 Regulatory proposal – Supporting document 5.19 – KPMG – Future network strategy – technology costs report*, 15 November 2018, p. 8.

Guaranteed Service Level reliability payments

SA Power Networks proposed a -$19.9 million ($2019–20) step change for GSL payments. While we are satisfied there will be a change in GSL obligations, we do not accept SA Power Networks' proposed forecast. We have instead included -$23.0 million ($2019–20) in our alternative estimate. Reasons for our alternative estimate are discussed below.

Table 6.14 GSL reliability payments step change ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
SA Power Networks' proposal	–4.0	–4.0	–4.0	–4.0	–4.0	**–19.9**
AER draft decision	–4.6	–4.6	–4.6	–4.6	–4.6	**–23.0**
Difference	**–0.6**	**–0.6**	**–0.6**	**–0.6**	**–0.6**	**–3.1**

Source: SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating Expenditure*, 31 January 2019, p. 23; AER analysis.

Note: Numbers may not add up to total due to rounding.

In January 2019, the Essential Services Commission of South Australia (ESCoSA) released its final decision on its review of the reliability framework that will apply to SA Power Networks from 1 July 2020 to 30 June 2025, including the GSL scheme.[176] Under the GSL scheme, SA Power Networks must automatically make payments to customers in the event that specified service levels are not met.[177]

The ESCoSA's final decision following its review includes a number of amendments to the existing framework. Payments for interruptions to electricity supply will be made when a customer experiences more than 20 hours of interruptions over one regulatory year.[178] This will replace the current system where payments are made for one-off outages lasting more than 12 hours. Payments will also be made when a customer experiences more than nine individual interruptions (each longer than three minutes) in a regulatory year. This will replace the current system of payments, which provides for increasing payments depending on whether a customer experiences more than nine, more than 12, or more than 15 interruptions over one regulatory year.

[176] Essential Services Commission of South Australia, *SA Power Networks reliability standards review - Final decision*, January 2019.

[177] Essential Services Commission of South Australia, *Electricity Distribution Code EDC/12.1*, January 2018, section 2.3.

[178] Essential Services Commission of South Australia, *SA Power Networks reliability standards review - Final decision*, January 2019, p. 35.

The ESCoSA stated that making the change to 'total duration payments' will manage the cost of the GSL scheme and refocus it on customers with ongoing, persistent reliability issues.[179] The ESCoSA's approach was supported by evidence that:

- Customers are not willing to pay as much as they do now for the GSL scheme
- Many payments are currently being made to customers that generally have average or good reliability
- Current levels of duration payments are not a strong driver of SA Power Networks' response to interruptions.

The ESCoSA's existing GSL scheme is uncapped, both in terms of total payments across all customers, and payments to individual customers for outages, and has multiple thresholds with increasing payments for longer duration outages.

A summary of the amendments ESCoSA made to the existing GSL scheme is shown in Table 6.15 with the amendments to the relevant payment thresholds shown in Table 6.16. The number of payments to individuals are capped under these changes.

Table 6.15 Amendments to the GSL scheme (effective 1 July 2020)

Current GSL Scheme	Changes to the scheme for the 2020–25 regulatory control period
Duration payment	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 regulatory control period

Source: Essential Services Commission of South Australia, *SA Power Networks reliability standards review - Final decision*, January 2019.

179 Essential Services Commission of South Australia, SA Power Networks reliability standards review - Final decision, January 2019 p. i.

Table 6.16 Amendments to GSL payments (effective 1 July 2020)

Current payment	Changes to the scheme for the 2020–25 regulatory control period
Duration of interruption payments – five payment levels • >12 and ≤15 hours, $100 • >15 and ≤18 hours, $150 • >18 and ≤24 hour, $200 • >24 and ≤48 hours, $405 • >48 hours, $605	Total annual duration of interruption • >20 and ≤ 30 hrs, $100 Total annual duration of interruption • >30 and ≤ 60 hrs, $150 Total annual duration of interruption • >60 hrs, $300
Frequency of interruption payments – three payment levels • >9 and ≤12 interruptions pa, $100 • >12 and ≤15 interruptions pa, $150 • > 5 interruptions pa, $200	Frequency of interruptions • >9 interruptions 3 minutes or longer pa, $100

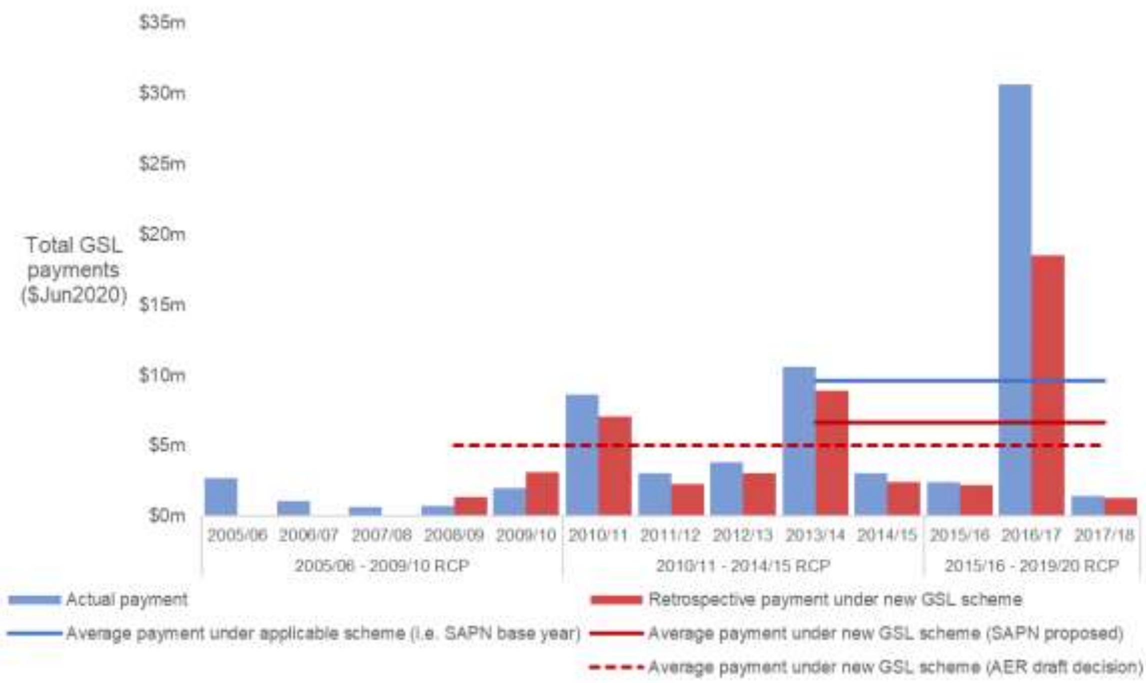
Source: Essential Services Commission of South Australia, *SA Power Networks reliability standards review - Final decision*, January 2019, p. 35.

Based on the likely impact of these changes we are satisfied that SA Power Networks' proposed GSL step change is prudent.

Given these changes, we examined SA Power Networks' actual GSL payments since 2005–06, and how much it would have paid out had the new GSL scheme (effective from 1 July 2020) been applicable. This is illustrated in Figure 6.7. We note that both the existing GSL scheme, and the amended GSL scheme that takes affect from 1 July 2020, require SA Power Networks to make payments for outages occurring on major event days.[180]

[180] Major event days refer to days where natural events are more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years' System Average Interruption Duration Index data.

Figure 6.7 Actual and retrospective GSL payments under the existing and new schemes ($ million, 2019–20)



Source: SA Power Networks, *2020–25* Regulatory *proposal – Supporting document* 6.4 – GSL Step Change 2020–25, January 2019; AER analysis.

SA Power Networks developed its base GSL opex of $9.7 million ($2019–20) by averaging its actual annual GSL expenditure over the five year period from 2013–14 to 2017–18 (the blue line in Figure 6.7).[181] SA Power Networks then calculated what its average annual GSL expenditure would have been over the same period had the new GSL thresholds been applicable ($5.7 million ($2019–20)), which is the red line in Figure 6.7). SA Power Networks' proposed GSL step change of –$19.9 million ($2019–20) over the 2020–25 regulatory control period (or –$4.0 million per year) is the difference between these two values.

We consider SA Power Networks' forecasting approach, and its use of actual historical GSL payments to be reasonable. However, we do not consider the 2013–14 to 2017–18 averaging period to be a reasonable basis for forecasting future GSL payments. The 2013–14 to 2017–18 averaging period includes 2016–17, the year in which South Australia experienced a state-wide blackout triggered by severe weather that damaged transmission and distribution assets. This event was followed by reduced wind farm

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181 SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating Expenditure*, 31 January 2019, p. 29; SA Power Networks*, 2020–25 Regulatory proposal – Supporting document 6.4 – GSL Step Change 2020–25*, January 2019.

output and a loss of synchronism that caused the loss of the Heywood Interconnector. The subsequent imbalance in supply and demand resulted in the remaining electricity generation in South Australia shutting down. Most supplies were restored in eight hours, however the wholesale market in South Australia was suspended for 13 days.[182]

We note that in its proposal SA Power Networks highlighted the uncharacteristically high impact of GSL payments in 2016–17:[183]

> *'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.'*

Further, it is important to note that following the 2016 'system black' event there have been a number of initiatives and contingencies put into place by the South Australian Government and the Australian Energy Market Operator to mitigate system security risk and to minimise the likelihood of a 'system black' scale event occurring again.

Our alternative methodology is to apply SA Power Networks' approach of using actual historical GSL payments, but to use a longer averaging period (in this case 2008–09 to 2017–18, which is the red dashed line in Figure 6.7). Increasing the sample size has the effect of reducing (in this case halving) the impact of GSL payments that were made in any one year. This results in our alternative estimate for the step change of –$23.0 million ($2019–20), which is $3.1 million ($2019–20) lower than SA Power Networks' proposal.

We consider our alternative approach of using a longer averaging period provides an estimate that is more reflective of the prudent and efficient costs for SA Power Networks in the future.

In assessing SA Power Networks' proposal and establishing our alternative estimate, we considered submissions from Energy Consumers Australia[184], and The Energy Project, Uniting Communities, and South Australian Financial Counsellors Association.[185]

Distribution licence fee

We received a submission from the South Australian Minister for Energy and Mining that stated the annual distribution licence fee is expected to be set at around $2.9 million per annum for the 2020–25 regulatory control period (compared to $2.3 million

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182 AER, *Investigation report into South Australia's 2016 state-wide blackout,* December 2018.

183 SA Power Networks, *2020–25 Regulatory Proposal – Attachment 6 – Operating expenditure,* 31 January 2019, p. 18.

184 Energy Consumers Australia, *AER Issues Paper: SA Power Networks Electricity distribution determination 2020 to 2025 submission*, May 2019.

185 Partnership of SA Financial Counsellors Association, The Energy Project, Uniting Communities, *Submission: Issues Paper – SA Power Networks revenue determination 2020–2025*, 22 May 2019.

per annum in the current period).[186] SA Power Networks did not include this it in its initial proposal, but advised late in our draft decision process that it is now seeking a step change in opex to reflect the higher distribution licence fee.[187]

It is not practically possible for us to consider such a late request as part of the draft decision. As a result, we have not examined the expected increase in the distribution licence fee in developing our alternative estimate for the purpose of the draft decision. Typically we would require there to be a new regulatory obligation for us to allow a step change. We will review the new information provided by SA Power Networks, and any feedback from interested parties on this matter, following our draft decision. We will consider this as part of our final decision.

6.4.4 Category specific forecasts

We have included one expenditure item, debt raising costs, in our alternative estimate of total opex which we did not forecast using the base-step-trend approach.

Debt raising costs

We have included debt raising cost of $7.2 million ($2019–20) in our alternative estimate. This is $13.3 million ($2019–20) less than the $20.5 million forecast ($2019–20) proposed by SA Power Networks.

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides for consistency with the forecast of the cost of debt in the rate of return building block.

We used our standard approach to forecast debt raising costs. SA Power Networks proposed an alternative approach to forecasting debt raising costs. We discuss our reasons for using our standard approach, rather than the approach proposed by SA Power Networks, in Attachment 3 to the draft decision.

6.4.5 Assessment of opex factors under the NER

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the 'opex criteria' under the NER, we have regard to the 'opex factors'.[188]

We attach different weight to different factors when making our decision to best achieve the NEO. This approach has been summarised by the AEMC as follows:[189]

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186 Government of South Australia, *Submission to the Australia Energy Regulator on the SA Power Networks' regulatory proposal 2020–25*, p. 4.

187 SA Power Networks, *Letter to AER – SA Power Networks Increased Distribution Licence Fee*, 30 August 2019.

188 NER, cl. 6.5.6(e).

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.17 summarises how we have taken the opex factors into account in making our draft decision.

Table 6.17 Our consideration of the opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to our most recent annual benchmarking report. Second, we must have regard to the benchmark opex that would be incurred by an efficient service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark opex that would be incurred by an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period. We have estimated an alternative opex estimate and have compared it with SA Power Network' proposal over the relevant regulatory control period. In doing this we relied on the information set out in our most recent benchmarking report.
The actual and expected opex of the Distribution Network Service Provider during any proceeding regulatory control periods.	To assess SA Power Networks' opex forecast and develop our alternative estimate, we have used SA Power Networks' estimated opex in 2018–19 as the starting point. We have examined SA Power Networks' historical actual opex and compared it with that of other distribution network services providers.
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	This factor directs us to have regard to the concerns of consumers, as revealed to us in their engagement with the service provider. Additionally, this factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their proposals, such that they are aware of, communicate and factor in the needs of consumers. Based on the information provided by SA Power Networks in its proposal and CCP 14's advice, we consider SA Power Networks consulted with consumers in developing its proposal. As identified in this attachment, SA Power Networks has taken into account some, but not all, of this feedback in its proposal. We have examined the issues raised by consumers in developing our alternative estimate of opex.
The relative prices of capital and operating inputs	We adopted price growth forecasts that account for the relative prices of opex and capex inputs. We generally consider capex/opex trade-offs in considering proposed step changes. One reason we will include a step change in our alternative opex forecast is if the service provider

[189] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, Final Rule Determination, 29 November 2012, p. 115.

Opex factor	Consideration
	proposes a capex/opex trade-off. We consider the relative expense of capex and opex solutions in considering such a trade-off. SA Power Networks proposed two step change as capex/opex trade-offs that we have assessed.
The substitution possibilities between operating and capital expenditure.	Some of our assessment techniques examine opex in isolation—either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs.
Whether the opex forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The incentive scheme that applied to SA Power Networks opex in the 2015–20 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have applied our approved base opex consistently in implementing the EBSS and forecasting SA Power Networks' opex for the 2020–25 regulatory control period.
The extent the opex forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	Our assessment techniques generally assess the efficiency of a network service provider's opex and/or capital expenditure at a total level. Provided that we do not find any material inefficiency in a network service provider's total opex in the nominated base year (which we use for our alternative estimate), we generally do not scrutinise a network service provider's related party transactions that may or may not be efficient and prudent. Given that we are satisfied that SA Power Networks' base year opex is efficient, we have not examined any of its related party arrangements.
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).	This factor is generally only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). SA Power Networks did not propose any opex changes that would be more appropriately included as a contingent project. We have not identified any opex project in the forecast period that should more appropriately be included as a contingent project.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	SA Power Networks stated it accepts the AER's framework and approach position to the demand management incentive scheme and demand management innovation allowance.[190]
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	In having regard to this factor, we must identify any regulatory investment test (RIT-D) submitted by the business and ensure the conclusions of the relevant RIT-D are appropriately addressed in the total forecast opex. SA Power Networks did not submit any RIT-D project for its distribution network.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised proposal under clause 6.10.3, is an operating expenditure factor.	We did not identify and notify SA Power Networks of any other opex factor.

Source: AER analysis.

190 SA Power Networks, *2020–25 Regulatory proposal – Attachment 11 – Demand management incentives and allowances*, 31 January 2019, pp. 4, 6.

A Analysis of Deloitte's and BIS Oxford Economics' real wage price index forecasts compared to actuals over the period 2007–18

We last looked at the accuracy of wage price index (WPI) growth forecasts in 2012. Given that the wage price growth has changed significantly since then, we have considered how well the two sets of WPI growth forecasts we have regularly used (namely, those from BIS Oxford Economics and Deloitte) compare with actual WPI growth.

We looked at 18 WPI growth forecast from Deloitte and 16 from BIS Oxford Economics over the period 2007 to 2018. These were the Australian utilities real and nominal WPI growth forecasts from the reports published by BIS Oxford Economics and Deloitte. We then compared them to actual Australian real and nominal WPI growth for the electricity, gas, water and waste services (utilities) industry reported by the Australian Bureau of Statistics (ABS).[191] We calculated the mean error and mean absolute error for each series as well as an average for Deloitte and BIS Oxford Economics.

We found that the forecasts from Deloitte were more accurate than the forecasts from BIS Oxford Economics (see Table A6.1 which presents the real analysis). The average of Deloitte's forecasts tracks closer to the actual ABS reported WPI (and has a smaller mean error and mean absolute error). In contrast, since 2011 the average of BIS Oxford Economics' forecasts has been persistently at, or above, actual real WPI growth (and have a higher mean error and mean absolute error).

[191] ABS, Catalogue number 6345.0, *Wage price index*, June 2019.

Table A6.1 Deloitte's and BIS Oxford Economics' real WPI forecasts compared to ABS actuals (2007–2018)

Forecast	Mean error	Mean absolute error	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Deloitte, November 2006	0.7	1.0	2.1	3.7	2.3	1.0	1.2	1.7						
BIS Shrapnel, March 2007	0.9	0.9	2.6	2.7	2.2	2.2	1.7	0.0						
Deloitte, April 2007	1.1	1.5	1.1	3.7	4.7	1.4	1.2	2.3						
Deloitte, September 2009	–0.1	0.7				1.6	0.4	0.6	1.1	1.6	1.7			
Deloitte, March 2010	0.0	0.5				1.9	1.0	0.9	1.0	1.4	1.6			
BIS Shrapnel, July 2010	0.8	1.2				1.0	1.8	1.8	2.5	2.4	2.1			
Deloitte, September 2010	0.3	0.7				1.5	0.6	1.0	1.5	2.3	1.6			
BIS Shrapnel, November 2010	0.8	0.9					1.8	1.7	1.7	2.0	2.1	1.8	1.7	
Deloitte, December 2010	0.4	0.4					0.9	1.3	1.8	2.1	1.8	0.9		
Deloitte, August 2011	0.0	0.4						1.7	1.6	1.1	1.0	0.3	0.7	
BIS Shrapnel, January 2012	1.2	1.2						1.7	1.9	2.7	2.4	2.2	2.5	
Deloitte, March 2012	–0.3	0.5						0.7	0.6	0.8	1.4	0.6	0.6	
BIS Shrapnel, April 2012	1.3	1.3						1.5	1.9	2.4	2.4	2.1	2.3	2.6
Deloitte, October 2012	0.2	0.5							1.4	1.2	0.9	0.9	0.9	1.0

Forecast	Mean error	Mean absolute error	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
BIS Shrapnel, October 2012	1.2	1.2						2.0	1.6	2.3	2.5	2.2	2.0	
Deloitte, February 2013	0.0	0.4							1.5	0.5	0.5	0.8	0.7	0.9
BIS Shrapnel, November 2012	1.1	1.2							1.7	1.8	2.5	2.6	2.0	
Deloitte, June 2013	–0.3	0.4							0.5	0.7	0.9	1.0	1.0	
BIS Shrapnel, November 2013	0.8	0.8								1.2	1.2	1.5	1.6	1.8
Deloitte, July 2014	0.0	0.4								0.7	0.7	0.4	0.4	0.9
BIS Shrapnel, November 2014	0.4	0.9									0.3	0.9	1.4	1.8
BIS Shrapnel, December 2014	0.4	0.6									1.1	0.7	1.1	1.4
Deloitte, February 2015	–0.1	0.5									1.4	0.1	0.3	0.5
BIS Shrapnel, May 2015	0.5	0.6									1.5	0.9	0.9	1.4
Deloitte, June 2015	–0.1	0.4									1.3	0.6	–0.1	0.5
Deloitte, February 2016	–0.3	0.4										0.8	–0.3	0.1
BIS Shrapnel, November 2016	1.2	1.2											1.4	1.5
Deloitte, February 2017	0.2	0.2											0.5	0.4
BIS Oxford, September 2017	0.6	0.6												0.6
BIS Oxford, October 2017	0.2	0.2												0.2
Deloitte, February 2018	0.3	0.3												0.3
Deloitte, July 2018	0.0	0.0												0.0

Forecast	Mean error	Mean absolute error	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Average, Deloitte	**0.1**	**0.5**	**1.6**	**3.7**	**3.5**	**1.5**	**0.9**	**1.3**	**1.2**	**1.2**	**1.2**	**0.6**	**0.5**	**0.5**
Average, BIS Oxford	**0.7**	**0.7**	**2.6**	**2.7**	**1.1**	**1.1**	**1.3**	**1.5**	**1.9**	**2.1**	**1.8**	**1.7**	**1.7**	**1.4**
Actual, ABS			**1.8**	**0.7**	**1.3**	**2.1**	**1.0**	**1.2**	**1.9**	**0.5**	**1.1**	**1.0**	**0.5**	**0.0**

Source: Access Economics, *Wages growth forecasts in the utilities sector,* 17 November 2006, p. iii; BIS Shrapnel, *Outlook for wages to 2012/13: Electricity, gas and water sector Australia and Victoria*, March 2007, p. 27; Access Economics, *Labour cost indices for the energy sector,* 12 April 2007, p. 66; Access Economics, *Forecast growth in labour costs,* 16 September 2009, p. xiv; Access Economics, *Forecast growth in labour costs: March 2010 report,* 16 March 2010, p. ix; BIS Shrapnel, *Wages outlook for the electricity distribution sector in Victoria*, July 2010, p. 1; Access Economics, *Forecast growth in labour costs: update of March 2010 report*, 20 September 2010, p. 48; BIS Shrapnel, *Labour cost escalation forecasts to 2016/17—Australia and Queensland, Final Report*, November 2010, p. 2; Access Economics, *Forecast growth in labour costs: Queensland and South Australia*, 13 December 2010, p. 64; Deloitte, *Forecast growth in labour costs: Queensland and Tasmania*, 15 August 2011, p. 68; BIS Shrapnel, *Labour cost escalation forecasts to 2016/17—Australia and Queensland*, January 2012, p. iv; Deloitte, *Forecast growth in labour costs: update of August 2011 report*, 9 March 2012, p. 63; BIS Shrapnel, Labour cost escalation forecasts to 2017/18—Australia and South Australia, April 2012, p. iv; Deloitte, *Forecast growth in labour costs: Victoria and South Australia,* 15 October 2012, p. 64; BIS Shrapnel, *Labour cost escalation forecasts to 2017—Australia and Victoria*, October 2012, p. iii; Deloitte, *Forecast growth in labour costs: Victoria and South Australia*, 25 February 2013, p. 64; BIS Shrapnel, *Labour cost escalation forecasts to 2017—Australia and Victoria*, November 2012, p. iii; Deloitte, *Forecast growth in labour costs in Victoria*, 13 June 2013, p. 69; BIS Shrapnel, *Real labour cost escalation forecasts to 2018/19—Australia and New South Wales*, November 2013, p. ii; Deloitte, *Forecast growth in labour costs in NSW, Tasmania and the ACT*, 24 July 2014, p. 8; BIS Shrapnel, *Real labour and material cost escalation forecasts to 2020—Australia and Victoria, Final report*, November 2014, p. ii; BIS Shrapnel, *Real labour cost escalation forecasts to 2018/19—Australia and New South Wales*, December 2014, p. ii; Deloitte, *Forecast growth in labour costs in NEM regions of Australia, 23 February 2015, p. 11*; BIS Shrapnel, *Utilities sector wage forecasts to 2019/20—Australia and South Australia*, May 2015, p. i; Deloitte, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, p. 10; Deloitte, *Forecast growth in labour costs in NEM regions of Australia*, 22 February 2016, p. 8; BIS Shrapnel, *Report on expected wage change to 2022/23*, November 2016, p. ii; Deloitte, *Labour price forecasts*, 6 February 2017, p. xiv; BIS Oxford Economics, *Real cost escalation forecasts to 2023/24*, September 2017, p. 2; BIS Oxford Economics, *Expected wages changes in the EGWWS sector to 2022/23—Australia and New South Wales*, October 2017, p. 2; Deloitte, *Labour price forecasts*, 7 February 2018, p. xiv; Deloitte, *Labour price forecasts*, 19 July 2018, p. xiv.

B Summary of Economic Insights' review of NERA's report on output weights

Technical concerns raised by NERA	Economic Insights' response
Opex PFP model	
The derivation of weights used is not transparent.	Economic Insights' 2013 report contains a full discussion of its approach to estimating output cost shares for the productivity index number models. Economic Insights also documented its approach in its 2014 benchmarking report and all subsequent benchmarking reports. Data, coding, and output files are included in the benchmarking results that accompany Economic Insights' benchmarking reports.
The ‘drivers’ are based on ‘tariff structure’.	Economic Insights used a functional outputs approach rather than a billed outputs approach for its opex PFP model.
The weights are ‘artificially constrained’ to be positive.	The Leontief cost model contains a non–negativity constraint on the output coefficients that is consistent with the underlying economic theory. If relationship between an output and opex is non-existent or negative, the model would produce a zero coefficient. None of the coefficients were found to be zero.
‘Very little data’ is used to estimate the weights.	The bottom up approach to estimating the simple Leontief cost function makes the most efficient use of the available Australian electricity distribution data given its lack of data variability and multicollinearity issues. The use of weighted average results across the 52 regressions minimises the risk from limited degrees of freedom from any single regression. The results are also corroborated by estimation of a flexible model over the whole Australian sample.
The use of energy throughput	
Overseas regulators are tending to ‘delink’ tariff structures from throughput.	Recent reforms to tariff structures in Australia, the US and the UK do not preclude the inclusion of energy throughput as an output. It remains the primary item consumers identify with their electricity supply and receives a small weight in the opex PFP model as would be expected on engineering grounds. It receives only a 3 per cent weight in our averaging process.
UK and US regulators are placing less emphasis on energy throughput in setting distributors revenue allowances.	The regulatory regimes in the US and the UK are quite different to Australia’s building blocks regulatory regime. Nonetheless, it should also be noted that recent analysis of productivity growth done by the Energy Policy Research Group for Ofgem included energy delivered as an output in all five models used.
The growth of embedded generation has disrupted the link between throughput and peak demand.	Economic Insights note that, for the industry as a whole, there have been small increases in both energy throughput and ratcheted maximum demand in recent years.
The least squares translog model	
The translog model’s second order coefficients produce counter–intuitive relationships.	NERA failed to recognise that the data are mean–corrected. The correct elasticities, presented in the files published on our website, are all positive as required.
Translog models have been rejected by a key UK regulator.	The Competition and Markets Authority in the UK was clear that its criticism only related to the application in question, which was criticised due to the small number of observations available. The Economic Insights translog models have several times more observations available. Cobb Douglas and

Technical concerns raised by NERA	Economic Insights' response
	translog models remain the most widely used in efficiency studies.
The second order coefficients are not included in forming weights when they should be.	Because the model uses mean–corrected data, calculating translog model output cost shares based on the first order coefficients produces the shares at the sample mean. The failure of NERA to recognise this means that both its calculation of elasticities and associated interpretations are incorrect.

Source: SA Power Networks, *2020-2025 Regulatory proposal, Supporting document 6.5, NERA - Review of the AER's proposed output weightings*, December 2018; Economic Insights*, Review of NERA report on output weights,* 30 April 2019*.*

C Confidential appendix