Revised AA4 proposal

Response to the ERA's draft decision

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Glossary

Term	Definition
A+DS	Analytics + Data Science
AA2	Second access arrangement
AA3	Third access arrangement
AA4	Fourth access arrangement
AA5	Fifth access arrangement
ABS	Above-benchmark surplus
Access Code	Electricity Networks Access Code 2004
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Akaike Information Criterion
AMI	Advanced metering infrastructure
AQP	Applications and Queueing Policy
BTP	Business Transformation Project
Capex	Capital expenditure
CPI	Consumer Price Index
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DLVCHS	Distribution Low Voltage Connection Headworks Scheme
DQM	Distribution Quotation Management System
DSM	Demand Side Management
EBSS	Efficiency Benefit Sharing Scheme
EIBs	Efficiency and innovation benchmarks
EMR	Electricity Market Review
ENUC	Excess Network Usage Charges
ERA	Economic Regulation Authority
ETAC	Electricity Transfer and Access Contract
GBA	Geoff Brown and Associates
GHD	GHD Advisory
GSM	Gain sharing mechanism
GSMAt	Gain sharing mechanism adjustment
IAM	Investment adjustment mechanism

Term	Definition
ICT	Information and Communications Technology
LoSEF	Loss of supply event frequency
MAIFI	Momentary average interruptions frequency index
MAIFIe	Momentary average interruptions frequency index event
MRP	Market risk premium
MSLA	Model Service Level Agreement
NER	National Electricity Rules
NFIT	New facilities investment test
NMS	Network Management System
NPC	Net present cost
NPV	Net present value
opex	Operating expenditure
RAB	Regulated asset base
RF	Radio frequency
RINs	Regulatory Information Notices
Saas	Software as a service
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SMI	System minutes interrupted
SSAM	Service standard adjustment mechanism
SSBs	Service standard benchmarks
SSTs	Service standard targets
STEM	Short Term Energy Market
STPIS	Service Target Performance Incentive Scheme
SUPP	State Underground Power Program
SVCs	Static VAR compensators
TEC	Tariff Equalisation Contribution
TOU	Time of use
WACC	Weighted average cost of capital

About this submission

This document has been prepared in response to the *ERA's Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, published by the Economic Regulation Authority (ERA) on 2 May 2018.

The ERA's draft decision was to not approve Western Power's proposed access arrangement revisions. The ERA advised it requires 91 amendments to the access arrangement proposal Western Power submitted on 2 October 2017.

As provided for by section 4.16 of the *Electricity Networks Access Code 2004* (Access Code), we submit a revised proposed access arrangement for consideration by the ERA. We also submit this response to the draft decision, which should be read in conjunction with the revised proposed access arrangement and its associated contract, policies and other documents.

This submission details Western Power's response to the ERA's draft decision, and along with the evidence submitted since 2 October 2017, constitutes the access arrangement information. It explains Western Power's position on each of the ERA's required amendments and is designed to help inform the ERA's final decision on the access arrangement for the fourth access arrangement period (AA4 – 1 July 2017 to 30 June 2022).

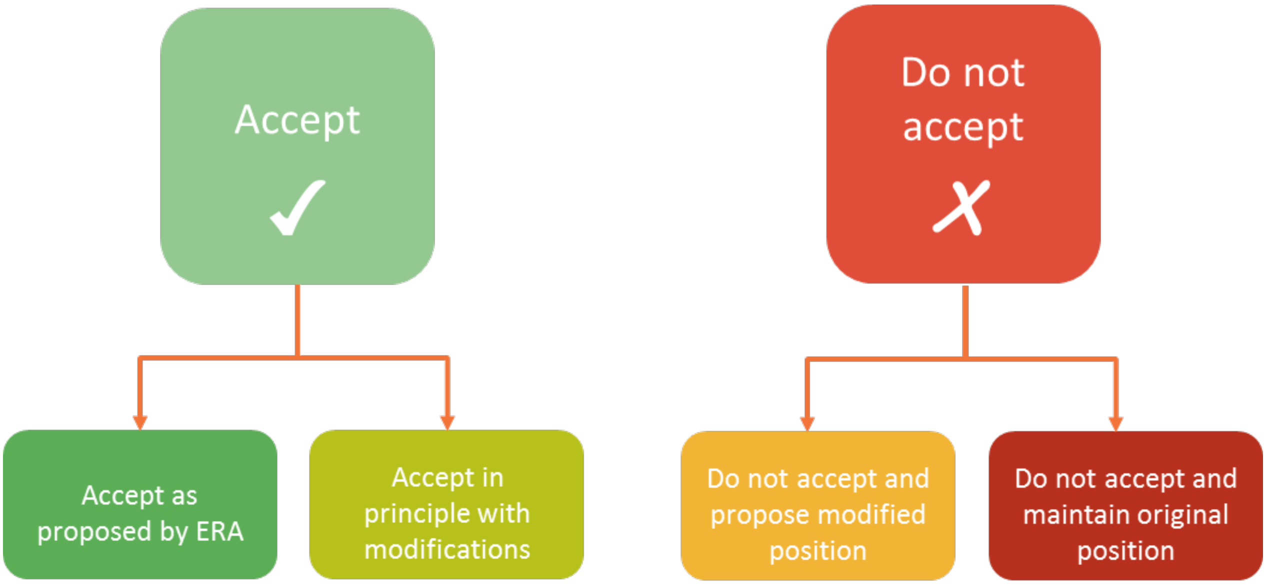
An appropriate citation for this submission is Western Power's **revised AA4 proposal**.

Responding to the ERA's required amendments

For each of the ERA's required amendments, Western Power has adopted one of four positions:

- **accepts the amendment as proposed by the ERA** – this is where we have accepted the ERA's amendment
- **accepts the amendment in principle, with modifications** – this is where we agree with the intent or principle behind the ERA's amendment, however we have not implemented the ERA's amendment exactly as required. This may be because changes elsewhere in our proposal (for example changes to expenditure values) mean values associated with the required amendment may vary from those in the draft decision. Alternatively, it may be because we have proposed an amendment to a document which achieves the same outcome the ERA seeks, but uses slightly different wording or approach
- **does not accept the amendment and proposes a modified position** – this is where we disagree with the ERA's amendment and have provided a revised or an alternative position in response to the draft decision
- **does not accept the amendment and maintains its original position** – this is where we do not agree with the ERA's amendment (or we believe the ERA may have misinterpreted our proposal) and have provided further information and rationale to support the position in our AA4 proposal.

Potential positions in response to the ERA's required amendments



Where Western Power's view differs from that expressed by the ERA in its draft decision, we have provided a detailed explanation of the rationale for varying from the ERA's amendment, as well as evidence to support our position.

For the reader's convenience, the order of the chapters and discussion of required amendments in this document follows the same structure as the ERA's draft decision.

Where drafting changes have been made to the proposed access arrangement or its associated policies, contract and other documents, these changes have been incorporated in the revised proposed access arrangement that accompanies this submission.

Access Code objective

All of Western Power's proposed revisions to the access arrangement are guided by relevant specific criteria and the Access Code objective, as defined in section 2.1 of the Access Code:

> *The objective of this Code is to promote the economically efficient:*
>
> *(a) investment in and*
>
> *(b) operation of and use of*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*

Criteria for approval of proposed revisions

Section 4.28 of the Access Code, which has the effect that the ERA's decision in relation to proposed revisions to an access arrangement is a 'pass or fail' assessment. Section 4.28 of the Access Code provides that when the ERA (the Authority) is:

> *… making a draft decision, final decision or further final decision, the Authority must determine whether a proposed access arrangement [to be read as proposed revisions] meets the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) and:*
>
> *(a) if the Authority considers that:*
>
> *(i) the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied — it must approve the proposed access arrangement; and*
>
> *(ii) the Code objective or a requirement set out in Chapter 5 (or Chapter 9, if applicable) is not satisfied — it must not approve the proposed access arrangement;*
>
> *and*
>
> *(b) to avoid doubt, if the Authority considers that the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied, it must not refuse to approve the proposed access arrangement on the ground that another form of access arrangement might better or more effectively satisfy the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable).*

Values used in this document

Unless otherwise stated, all financial values in this document are expressed in $ million real at 30 June 2017. Amounts in various tables may not sum due to rounding. Refer to the revenue and expenditure models submitted with this document for detailed financial values.

Key messages

Key messages

- Western Power accepts around two-thirds of the ERA's required amendments either in full or in principle.
- Western Power and the ERA are broadly aligned on most of revenue building blocks.
- Time of use network tariffs will not be mandatory, and several improvements have been made to the standard access contract, the access arrangement policy documents and how metering services are described.
- From 2017/18 to 2021/22, Western Power will invest around $3,388 milion of capital and $1,831 million of operating expenditure to maintain network safety and current levels of overall reliability. Western Power will also continue to pursue new technologies, advanced metering, and alternative network solutions.
- Average distribution customer bills will increase below inflation, with the average impact on residential customers' electricity bills being an additional $2 per annum.
- Tariffs for customers connected to the transmission network, typically generators and large businesses, and major industrial loads, are increasing more steeply. This follows the significant transmission tariff decreases over the past five years.
- Western Power has proposed several options to limit the impact of tariff increases on transmission customers, and will work with the ERA to finalise transmission network tariffs.
- The areas where Western Power and the ERA most strongly disagree relate to changes the ERA has made to the adjustment mechanisms and price contol for the AA4 period.
- The ERA has removed the potential for Western Power to be penalised or rewarded for performance under its service inventive regime, and has made changes to several mechanisms under the regulatory framework that when combined, do not promote efficient investment in and operation of the network.
- Over the past five years, the access arrangement resulted in service improvements for customers, and incentivised Western Power to reduce its costs by almost $1 billion, with only moderate price increases for customers. Therefore Western Power does not consider the current adjustment mechanisms and price control require fundamental changes.
- Western Power has provided further information to the ERA on these matters and is optimistic an access arrangement that is acceptable to all parties, resulting in positive outcomes for customers, can be agreed when the ERA makes its final decision.

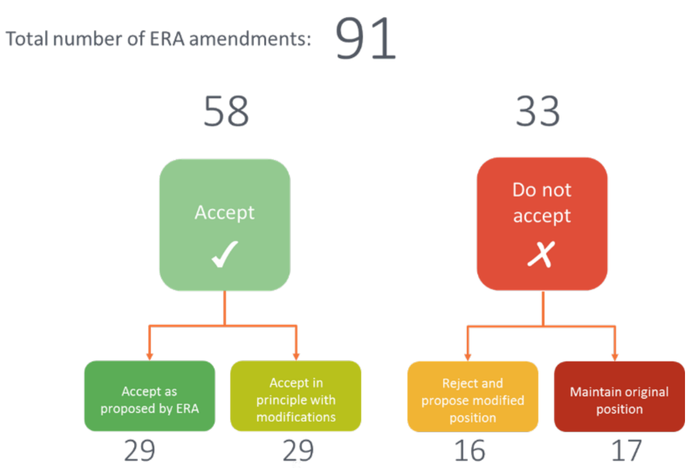
1. Executive summary

1. Western Power submits this revised AA4 proposal in response to the ERA's draft decision. The ERA's draft decision was to not approve Western Power's proposed access arrangement revisions. The ERA has made 91 amendments to the access arrangement originally proposed by Western Power, as well as excluding a number of expenditure items from target revenue, and seeking additional information on forecast investment.

2. We have reviewed the ERA's draft decision in detail and have prepared a revised proposed access arrangement for consideration by the ERA. Western Power and the ERA are aligned on a broad range of issues, and as such we have accepted (either in full or in principle) around two-thirds of the ERA's required amendments.

3. We agree with many of the ERA's proposed changes to the standard access contract and the access arrangement policy documents. We also accept some of the ERA's definitions of reference services, and have agreed to change the new time of use reference services so they are not mandatory.

Figure 1.1: Responses to the ERA's 91 required amendments



4. The weighted average cost of capital (WACC), typically one of the most contentious areas of any regulatory determination, is also an area in which we are in broad alignment with the ERA. We have adopted all but one of the ERA's WACC parameters, providing an alternative position on the estimate of the market risk premium (MRP) only. Forecast tax and depreciation methodologies are also elements on which we concur.

5. With regard to forecast expenditure, though the draft decision specifies reductions to both capital and operating expenditure forecasts, the ERA and its technical consultant GHD Advisory support many of our proposed investments in principle. However, they require further information to be able to include them in the target revenue calculation. Expenditure on transmission asset replacement and advanced metering infrastructure (AMI) are notable examples.

6. Where possible, we have provided further evidence to support aspects of our expenditure program. We submit that the forecast expenditure in this AA4 revised proposal is prudent, efficient, and reasonably expected to meet the requirements of the new facilities investment test (NFIT).

7. Despite alignment on many of the major revenue building blocks, there are aspects of the ERA's draft decision Western Power cannot accept. For the most part these aspects relate to the form of price control and adjustment mechanisms which, while not having a major impact on AA4 target revenue, are likely to result in unfavourable outcomes for customers and Western Power in the future.

8. The ERA proposes a fundamental change to the form of price control that applies to Western Power, effectively moving the business from a revenue cap to a price cap. Not only would this change be impracticable given 12 months of the access arrangement period has already elapsed, it also has other negative impacts such as diminishing incentives for Western Power to pursue demand side management and edge-of-grid solutions over the longer term.

9. The ERA has also redesigned the service standard adjustment mechanism (SSAM) so that it no longer provides penalties or rewards for service performance. This change, particularly when combined with the ERA's proposal to award penalties for operating cost overspends (under the gain sharing mechanism), results in an access arrangement that creates perverse incentives, in that Western Power will be encouraged to allow service performance levels to decline. While Western Power will seek to maintain service performance levels, it seems counter-intuitive to change the adjustment mechanisms such that they discourage the types of behaviours customers have told us they value.[1]

10. We understand that the ERA's primary motivation for making such fundamental changes to the form of price control is the desire to avoid sudden material adjustments in prices (referred to as price shock[2]). However, we are unclear how the ERA's proposed amendments will address this. Moreover, the ERA has not demonstrated that price shock would occur under the current revenue cap (which Western Power is proposing to maintain), nor that the mechanisms that currently exist are incapable of mitigating price shock, should it arise.

11. It is in these fundamental changes to the adjustment mechanisms and form of price control where we find ourselves in strongest disagreement with the ERA, and we have put forward our positions in this submission accordingly.

12. Nonetheless, we believe we are not too far from reaching agreement with the ERA on most aspects of the access arrangement. We are optimistic an access arrangement that will help deliver positive outcomes for customers while enabling Western Power to continue to operate efficiently and safely, will be approved.

13. Key elements of our revised AA4 proposal are summarised in the following sections.

AA4 target revenue and pricing

14. Target revenue in this revised AA4 proposal is $7,721.3 million. This is 3.9 per cent higher than the amount determined by the ERA in its draft decision, and 2.2 per cent lower than our proposal in October 2017.

15. The difference between our and the ERA's estimates is the result of variances to several of the revenue building blocks, including the forecast regulated asset base (RAB), WACC, forecast opex and revenue adjustments from the AA3 period. For the most part, we are aligned with the ERA on the methodology behind each of the building blocks, if not the precise calculation. We consider our revised revenue proposal will allow Western Power to recover its forward looking efficient costs and represents an amount that will enable us to maintain network safety and reliability, and to do this without materially increasing customers' electricity bills.

16. The overall impact of our revised AA4 proposal on network tariffs is low, resulting in price decreases in real terms.[3] The following table shows the estimated movements in electricity bills over the AA4 period if Western Power's AA4 proposal is approved and implemented in full.[4]

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1 As discussed in the AA4 proposal, Western Power's customer engagement program found that customers want Western Power to maintain service levels and pursue alternative technology where efficient to do so.

2 Section 6.4(b), Electricity Networks Access Code 2004.

3 The estimated average annual price increase across all tariffs is less than the current rate of inflation.

4 Note these figures are based on average annual usage in each customer class, and relate to the network tariff only. Western Power has no control over the electricity generation costs or how much of any cost savings or increases are passed on to the customer by electricity retailers.

Table 1.1: Estimated annual change in average electricity bills resulting from the revised AA4 proposal, nominal per cent per annum

Customer type	2017/18	2018/19[5]	2019/20	2020/21	2021/22	Compound annual growth rate (CAGR)
Residential	0.0%	1.5%	1.5%	0.7%	1.0%	0.3%
Small business	0.0%	3.5%	2.5%	2.2%	2.6%	1.8%
All distribution customers	0.0%	2.1%	1.6%	1.2%	1.5%	0.6%
All transmission customers	0.0%	12.8%	12.8%	12.2%	11.8%	9.4%
All customers	**0.0%**	**2.6%**	**2.1%**	**1.7%**	**2.0%**	**1.0%**

17. The estimated impact on residential electricity bills is around 0.3 per cent per annum, which is lower than the current inflation rate. This equates to an average increase for each residential customer of around $2 per annum over the AA4 period.

18. As can be seen from the above table, while the price impact on residential customers and small businesses is low, transmission-connected customers will see average price increases of around 9.4 per cent. As submitted in our original AA4 proposal, this is the result of a revenue smoothing issue that means the transmission network tariff must increase during the AA4 period to 'catch up' with target revenue following the tariff decreases which occurred during the AA3 period.[6]

19. We proposed several options[7] to mitigate the price impact on transmission customers in our AA4 proposal, including changing the timing of transmission and distribution revenue collection such that transmission tariff increases would be capped at 10 per cent per annum. The ERA has not accepted any of our mitigation options.

20. In its draft decision, the ERA states:

> *The ERA considers there are a range of revenue smoothing profiles that would meet the Access Code requirement to avoid price shocks, which Western Power should consider. The ERA requires Western Power to amend its target revenue to be consistent with the draft decision but should review the smoothed target revenue to reduce the likelihood of price shocks in the next access arrangement period.*[8]

21. There is no simple solution to the transmission tariff path issue, and the ERA provides no further guidance on the range of revenue smoothing profiles it considers would avoid price shock. Indeed, the transmission revenue profile put forward by the ERA in its draft decision results in price increases of 12.43 per cent per year (in real terms) for transmission connected customers. We have therefore modelled several further transmission tariff options, and have selected the option presented in the following table.

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5 Tariff prices to remain at 2017/18 levels until 31 October 2018. 2018/19 tariff change at the commencement of the new access arrangement (1 November 2018).
6 Transmission network tariffs have decreased on average by 7 per cent (nominal) per year over AA3.
7 Four practicable options were submitted for consideration by the ERA in Attachment 10.8 of the AA4 proposal.
8 Paragraph 118, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Table 1.2: AA4 average reference transmission tariffs, nominal per cent per annum

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average
Transmission tariffs	0.0%	13.0%	13.0%	13.0%	13.0%	10.4%

22. The transmission tariff path of 13 per cent increases per annum is designed to meet the ERA's criteria of achieving a smooth tariff path and aligning with transmission build block revenue by the end of the AA4 period, to avoid similar transition issues when we reach the AA5 period. This transmission tariff path is achieved by Western Power deferring collection of $171 million of transmission revenue.

23. We recognise that the magnitude of the price increases, though similar to those proposed by the ERA in its draft decision, is significant. Though we have identified a preferred option for the purpose of this AA4 revised proposal, we welcome engagement with the ERA on the transmission tariff issue and are happy to work with the ERA to finalise a smoothing profile that best meets all customer and other stakeholder requirements.

Forecast expenditure

24. Forecast capital expenditure (capex) in the revised AA4 proposal is $3,388 million.[9] This is $126 million less than the October 2017 proposal. In its draft decision, the ERA excludes $466 million of forecast capital expenditure from Western Power's forecast regulatory asset base (RAB), largely related to the transmission network. The ERA, Geoff Brown and Associates (GBA) and GHD Advisory (GHD) all comment positively on Western Power's asset management approach and investment governance framework however, the ERA requires further information on a number of programs to be able to approve them for inclusion in the forecast RAB.

25. We have sought to provide this further information in this response and have adjusted our capex forecast to reflect that information. Notable changes are in transmission growth, where we have reviewed the need for a new substation in the CBD in light of revised demand forecasts, and have removed it from the AA4 forecast. We have also removed related expenditure from the distribution growth forecast.

26. The ERA's largest reductions to capex are in transmission asset replacement, excluding $114 million.[10] We maintain that our proposal to replace and/or refurbish poor condition and poor performing transformers, protection systems, switchboards, static VAR compensators and primary plant is essential if we are to maintain the safety and reliability of the network over the AA4 period and beyond. We have therefore provided further evidence to justify the inclusion of these transmission asset replacement programs in the forecast RAB, and intend to deliver them in full during the AA4 period.

27. We have also provided further justification for the installation of the communications infrastructure to support the Advanced Metering Infrastructure (AMI) program in the distribution network. The ERA appears to support in principle the installation of advanced meters, and states that:

> *The ERA considers installing modern electronic devices with enhanced capabilities in new properties and when replacing old meters is consistent with good electricity industry practice and, therefore, is consistent with the new facilities investment test.*[11]

28. However, the ERA excludes Western Power's proposed expenditure associated with the communications and IT elements critical to supporting the AMI program, as it considers the benefits were unclear and that a positive net present value (NPV) of the program had not been demonstrated. We accept that there were

[9] Net of gifted assets and capital contributions.

[10] Before allocation of indirect costs and escalation.

[11] Paragraph 451, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

some inconsistencies in the data provided to the ERA and GHD and have therefore provided updated information to clarify our position.

29. The updated cost benefit information and related sensitivity analysis shows that even under conservative assumptions, the AMI program will deliver a positive NPV and is therefore reasonably expected to satisfy the requirements of the NFIT. The AMI program remains one of Western Power's most important programs of work, and it is vital that the IT and communications infrastructure (the infrastructure that makes advanced metering 'advanced') is installed if customers are to realise the full benefits.

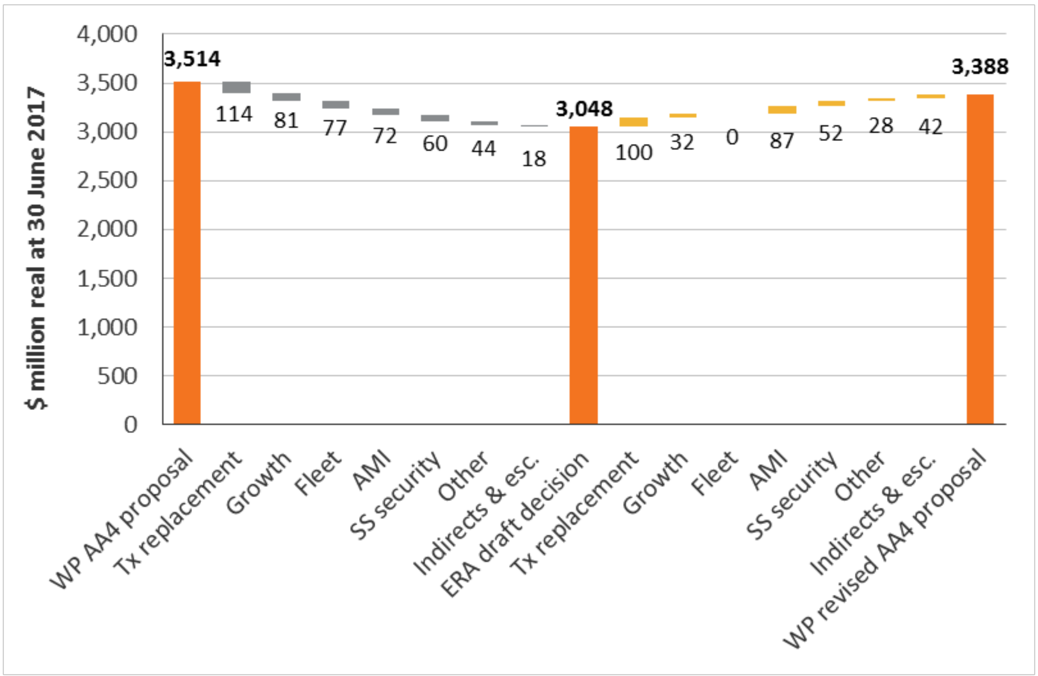
30. Other aspects of the capex program on which we have provided further information include investment in substation security and a new customer relationship management system which will enhance the quality of customer service and improve the overall customer experience.

31. We maintain that the capex program in this revised AA4 proposal will enable Western Power to:

- maintain the current levels of safety risk associated with the network
- maintain current levels of service standard performance for the distribution and transmission network (reliability of supply and security of supply), as well as call centre and streetlight performance
- meet forecast growth in the customer base and demand
- satisfy compliance requirements
- continue to improve the efficiency of operations.

32. The following chart shows the changes in the revised AA4 forecast capex proposal compared to the AA4 submission and the draft decision.

Figure 1.2: Changes in revised AA4 forecast capex[12] compared to the draft decision and AA4 proposal



33. Our revised operating expenditure (opex) proposal is $1,831 million, compared to the ERA's draft decision of $1,695 million.

12 Excluding indirect costs.

34. Though we have adopted some of the ERA's recommendations (for example we have used the latest Economic Insights data to apply scale escalation), we have retained most elements of our original proposal and have provided further evidence to justify these.

35. We used the well-established base-step-trend method to estimate our forward-looking efficient costs. The ERA and GHD accepted this approach and determined that the revealed costs that inform the base year were efficient.

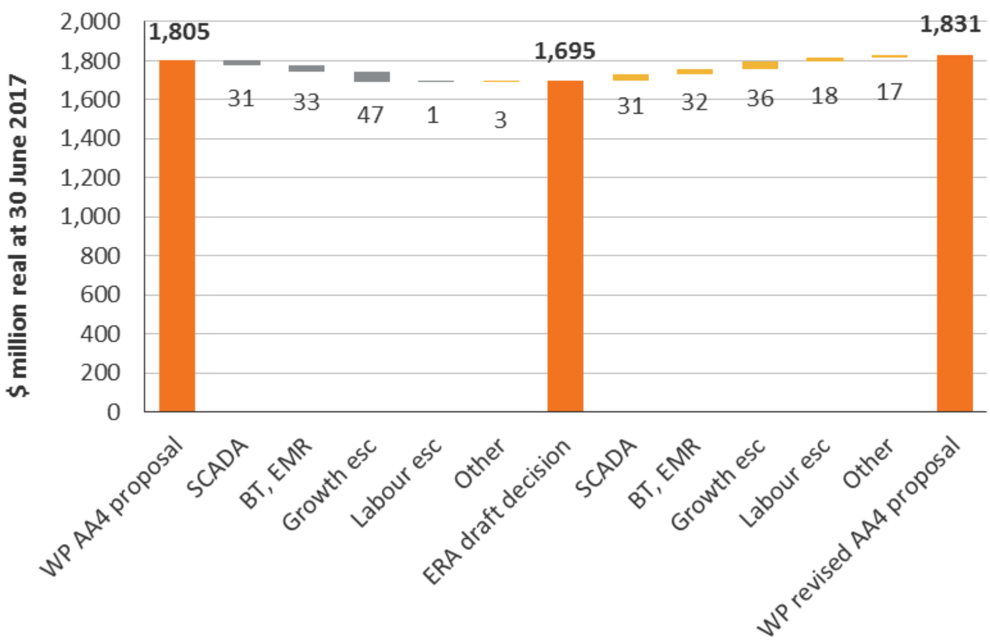
36. However, the ERA (on the advice of GHD) subsequently made downward adjustments to the efficient base year based on a bottom-up assessment of discrete programs. This form of bottom-up assessment is incompatible with a top-down (revealed cost) forecast and we have therefore not accepted these changes.

37. The ERA also excluded a number of non-recurrent costs, including $28 million required to complete the highly successful Business Transformation Project (BTP). As discussed in the AA4 proposal, the BTP has delivered more than $330 million in efficiencies, and the $28 million cost of completion is fundamental to Western Power being able to further reduce its total AA4 operating expenditure by more than $158 million compared to AA3.

38. In our AA4 proposal, we included a $5 million recurrent negative step change to opex and a $12 million recurrent negative step change to indirect costs from 2017/18 onwards and clearly articulated that this was linked to the successful completion of the BTP. We also proposed a 1.0 per cent annual efficiency dividend as a result of the BTP, which the ERA approved in its draft decision. We contest that costs of $28 million are far outweighed by an expected in-period saving of $158 million and the related ongoing benefit of these cost reductions to our customers over future access arrangement periods.

39. The following chart shows the movements in the revised opex forecast compared with the draft decision.

Figure 1.3: Changes in revised AA4 forecast opex compared to the draft decision



Opening RAB

40. The calculation of the AA4 opening RAB is an area in which the ERA and Western Power are reasonably aligned. The ERA's technical consultant GBA conducted a thorough review of Western Power's historical capex (which is included in the RAB) and made the following general statement:

> *Over the course of AA3, Western Power has significantly improved the efficiency of its management of capital expenditure (capex). These improvements relate both to the selection of capex projects and to the use of capital once projects have been committed for implementation. Total capex over AA3 was 22% lower than the approved expenditure forecast at the start of the regulatory period, and despite this, Western Power has still been able to meet or exceed the service levels that it promised its stakeholders. While some capex reductions were due to forecast demand growth not materialising, we think that improved project identification and expenditure management were significant factors in delivering this result.*[13]

41. It is worth noting GBA also conducted ex-post reviews of Western Power's capital expenditure for the ERA during the second and third access arrangement (AA2 and AA3) review processes, and as such has closely scrutinised Western Power's governance processes, investment decisions and asset management improvements over the past decade.

GBA identifies the following expenditure it considered did not entirely meet NFIT requirements:

- future decommissioning costs for various substations ($7.16 million)
- provision for future removal of asbestos ($2.6 million)
- undergrounding the Manning-Osborne Park 132 kV transmission line ($2.13 million)
- capitalisation of intellectual property related to work undertaken in preparation for the transition to the national regime ($6.7 million).

42. We have reviewed GBA's findings and accept that these items should not be added to the AA4 opening RAB and have removed them from our target revenue estimate accordingly.

43. The ERA identifies three further items it considers did not entirely meet NFIT requirements:

- $1.8 million distribution capital expenditure for the Perenjori battery storage system project
- $0.7 million for a transmission capital contribution for the medical centre substation
- $28.9 million for unplanned wood pole replacement, which it considers should have been included in operating expenditure.

44. We accept removal of the capex associated with the Perenjori battery storage project, as we had flagged to the ERA that this project may not be reasonably expected to satisfy the NFIT.

45. We have not accepted the ERA's other two adjustments for the medical centre substation capital contribution and the unplanned wood pole replacement. The $0.7 million medical centre substation capital contribution was not included in our AA4 RAB calculation and therefore an exclusion is not required.

46. In this submission we provide further information to clarify that the $28.9 million was not included in the AA3 opex amount and therefore has not already been recovered via reference tariffs. To include the $28.9

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13 Page 1, *NFIT Review of Western Power's Capital Expenditure during the AA3 Regulatory Period, Geoff Brown & Associates*, April 2018.

million expenditure on emergency wood pole replacements in the AA4 opening RAB would not constitute a double-count.

WACC, tax and depreciation

47. The WACC, tax and depreciation revenue building blocks are areas in which we generally accept the ERA's estimating methodology. For depreciation and tax, we accept the ERA's estimating approach, albeit we have arrived at different values due to changes elsewhere in the access arrangement.

48. With regard to WACC, the only area where we differ from the ERA's position is in respect to the market risk premium (MRP), which the ERA has set at 6.2 percent. We believe this is lower than what would be reasonable for a benchmark efficient firm. Though we are not disputing the MRP range the ERA has developed (5.6 to 7.6 percent), we consider it is not appropriate that the ERA has selected a point estimate lower than the mid-point, particularly when the mid-point or higher has been selected by the ERA in recent decisions using almost identical datasets.

49. We therefore propose a MRP of 6.6 percent, based on the mid-point of the ERA's MRP range. This revises our proposed WACC to 6.12 percent, compared to the ERA's 6.00 percent.

Form of price control

50. The ERA requires that the current form of revenue cap price control be amended by:

> *removing the correction factor for under or over-recovery of target revenue for prior periods from the price control formula; and*
>
> *requiring the forecast revenue recovery from Western Power's proposed tariffs in each year's Price List to be based on customer numbers and volumes consistent with the demand forecast approved with the AA4 decision.*[14]

51. These changes remove the opportunity for Western Power's target revenue to be adjusted for actual demand and requires that prices be constrained to the demand forecasts approved by the ERA. Though not explicitly stated by the ERA, this constitutes a price cap form of price control.

52. Changing the form of price control is one of the most fundamental changes to an access arrangement that can be made. It is an amendment that would also require a fundamental change to Western Power's view of forecast expenditure, and the suite of services and tariffs we offer customers. It is not practicable to move to price cap regulation at this stage of the access arrangement review process, particularly when the AA4 proposal and its associated services, tariffs and costs have been formed on the presumption that the revenue cap form of price control, which applied in each previous access arrangement period, will be maintained.

53. A move to a price cap has not been contemplated by Western Power during the development of its services, investments and tariffs for the AA4 period. Adopting a price cap was not raised during any communications by the ERA until its draft decision, including when it released its AA4 Issues Paper[15] in October 2017. The ERA did not engage with Western Power on this fundamental issue at any point during the AA4 review process.

54. The ERA has made a decision that alters the central feature of the access arrangement without providing adequate reasons, as required by section 4.27 of the Access Code. The ERA has also not demonstrated how the form of price control proposed by Western Power and accepted in each other access arrangement will

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[14] Paragraph 90, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[15] Issues Paper on Proposed Revisions to the Western Power Network Access Arrangement (2017/18 to 2021/22 - AA4), ERA, 31 October 2017.

not satisfy the Access Code objective during the AA4 period, as required by section 4.28 of the Access Code. The ERA cites price shock as a driver, but has not provided evidence that price shock is likely to occur or cannot be adequately mitigated under a revenue cap form of price control.

55. In addition, we consider any change to the form of price control must be complemented by a re-assessment of the investment risk (WACC) and the suite of associated incentive mechanisms, as these are all inextricably linked and should be designed to drive consistent rather than conflicting behaviours.

56. As such, we believe it is vital that the ERA revisits its decision on the form of price control and reverts to the revenue cap as proposed by Western Power in its original proposal.

Service standards and SSAM

57. In our original AA4 proposal, we submitted a suite of service standard benchmarks (SSBs) and service standard targets (SSTs) designed to incentivise Western Power to maintain services at existing (AA3) levels. This level of service performance is consistent with the findings of our customer engagement program.

58. As such, SSBs were set by averaging the 99th percentile of the distributions of best fit for each measure, and similarly the SSTs were set by averaging the 50th percentile of the distributions of best fit. However, the ERA has rejected these measures, instead requiring SSBs be set at the 97.5th percentile of the single distribution of best fit and the SSTs at the 50th percentile of the single distribution of best fit.

59. We have not adopted the ERA's revised SSBs, foremost because they are set at a level that would require additional investment to improve service performance above what customers have told us they are willing to pay for. Western Power has not proposed forecast capex to deliver such improvements.

60. Because service performance improved over the AA3 period, our proposed service targets already represent a higher level of service than the AA3 average. We have set the AA4 targets using a statistical method that reflects the service customers experienced during the AA3 period. The AA4 SSBs and SSTs are already more difficult to achieve than targets set at the beginning of the AA3 period, so the likelihood of Western Power exceeding them based on the level of investment we are proposing is low. Further, we do not accept the use of the single distribution of best fit because the averaging of the distributions of best fit presents a statistically sound method to reduce the variability of the outcome.

61. Notwithstanding this, the ERA has made a much more fundamental change to the service incentive framework that makes the setting of the SSTs irrelevant. The ERA proposes that the service standard adjustment mechanism (SSAM) has no penalties or rewards attached to it, which means no incentive rates are set to reflect the value to customers of service performance.

62. The SSAM is a mechanism prescribed by the Access Code that is designed to provide an incentive to a network service provider to achieve a specific level of performance. Where performance equals the target (as is proposed by Western Power for the AA4 SSAM), the service provider receives no rewards or penalties. If it allows service to decline it receives a penalty, if it exceeds the target it receives a reward.

63. In addition to being a device for incentivising service levels that customers value, the SSAM acts as a vital counterbalance to the gain sharing mechanism (GSM), which provides rewards for operating efficiencies. Where a service provider reduces opex in order to earn rewards under the GSM, if it allows service levels to decline below its SSTs, then the GSM reward is offset by penalties under the SSAM. This prevents service providers from being rewarded for efficiencies despite poor performance and/or poor customer service.

64. If the SSAM rewards and penalties are switched off, as proposed by the ERA, then this counterbalance no longer exists. The network service provider would have a perverse incentive to allow service levels to decline where cost savings can be made. We consider this contrary to the Access Code objective.

65. We are unclear why the ERA has determined it prudent to remove all rewards and penalties from the SSAM. During the AA3 period, Western Power improved service performance and as a result is entitled to a positive revenue adjustment during the AA4 period. Western Power's customers are now, on average, receiving a better level of performance than ever before despite Western Power spending almost $1 billion (total expenditure) less than forecast in the AA3 period and maintaining these lower expenditure levels during AA4. SSAM rewards and penalties will ensure that the performance improvement experienced by customers during the AA3 period, which they have paid for through a revenue adjustment in AA4, is maintained during the AA4 period.

66. The SSAM rewards achieved during the AA3 period are not a windfall gain. They have been delivered via a measured program of investment that has improved performance at an efficient level of expenditure. The SSTs and the financial penalties/rewards form part of our investment governance approach and are used to inform business cases and investment decisions. Removing the rewards and penalties removes an integral part of our asset management process.

67. Further, our AA4 SSAM proposal contains more difficult targets than AA3, with smaller potential rewards. Given the lag between investment and actual service improvement, it is worth noting that service performance during the AA4 period will be influenced by expenditure levels during AA3 that were almost $1 billion lower than forecast. As a result, we consider the likelihood of Western Power receiving significant rewards in AA5 is low.

68. We therefore submit that the SSAM rewards and penalties we proposed in our original AA4 proposal apply for the AA4 period.

Gain sharing mechanism

69. The GSM is designed to provide an incentive for Western Power to reduce its operating costs (though not at the expense of service performance) by providing for a positive adjustment to target revenue in the following access arrangement period commensurate with a proportion of the efficiencies it has achieved.

70. During the AA3 period the GSM has been highly effective, providing incentive for Western Power to reduce its operating costs by more than 24 per cent, resulting in a $277.9 million benefit in the AA4 period. The AA3 period was the first time Western Power has earned rewards under the GSM, largely as a result of the business transformation project and similar efficiency programs that were undertaken over the past five years. Though we will continue to pursue further efficiencies, we do not expect a similar magnitude of GSM rewards in the future.

71. The ERA proposes a number of changes to the GSM, including reducing the time period over which benefits are retained and the allocation between the transmission and distribution businesses. However, the most fundamental change required by the ERA is to make the GSM symmetrical – in that in addition to providing gains to be shared it also provides for losses to be shared.

72. We do not accept this amendment, not least because a symmetrical GSM is not permissible under the Access Code. There are also economic and practical arguments against a symmetrical GSM, particularly in light of the ERA's other required amendments. For example, if the ERA retains its view that the SSAM should have no rewards or penalties attached to it, then there would be an incentive for Western Power to allow service levels to decline (as there is no financial penalty). This incentive is magnified if there is also a potential penalty under the GSM for overspending opex. Combined, these two adjustment mechanisms would serve to encourage a network service provider to allow service levels to fall towards the minimum (compliant) standard in order to avoid potential penalties under the GSM.

73. We therefore do not accept the ERA's proposed changes to the GSM.

Reference services

74. In the AA4 proposal, we proposed changes to the existing suite of reference services, as well as introducing new time of use (TOU) and demand tariffs. The ERA approved most of the changes, including the new TOU services, however it requires that the new TOU tariffs are not mandatory.

75. We accept this change and have made the necessary changes to the access arrangement.

76. The ERA proposes a further change, requiring Western Power to unbundle metering services from reference services and specify separate metering services as reference services based on the meter reading services required by users.

77. We agree with the ERA's desired outcomes relating to metering services, namely providing:

- clarity and detail on what standard meter services are provided
- choice to users who seek a different level of metering.

78. We also generally agree with the desired outcome that recovery of metering costs should be more closely aligned with a user-pays basis and based on the cost of the service.

79. Where we differ from the ERA's view is in the manner by which the abovementioned outcomes are achieved. We do not agree that unbundling metering services from the reference services proposed by Western Power and specifying separate meter reference services is necessary to achieve these outcomes, and in fact would:

- not align with the legislative framework for metering in Western Australia
- lead to contractual issues under existing access contracts which contemplate one reference service (and one tariff and therefore charge) at each network connection point
- result in additional and unnecessary implementation costs to Western Power and other users.

80. In any event, we do not consider unbundling metering services is necessary in order to give users choice of metering services. We consider users will be (and have previously been) able to obtain the types of interval and other metering services identified by the ERA in its draft decision, as well as other more bespoke metering services. In fact, we consider there is more flexibility under the current arrangements for users to seek additional types of metering services.

81. We have therefore not adopted the ERA's required amendment, and have retained the existing reference service structure whereby a standard metering service is included as part of each relevant reference service. If users seek a different level of metering service, then they can obtain this under the service level agreement and service negotiation provisions of the Metering Code.

82. To assist users to understand what standard metering services are included in each reference service, a metering guide has been annexed to the Reference Service Appendix E, which is attached to the revised proposed access arrangement.

Standard Access Contract and policies

83. Some 50 of the ERA's 91 required amendments related to the Standard Access Contract, Contributions Policy, Applications and Queuing Policy, and the Transfer and Relocation Policy (contract and policies).

84. These required amendments related to a variety of matters; some were substantive while others were minor drafting amendments.

85. Of the required amendments made to the contract and policies, Western Power has accepted the amendment or the principle behind the amendment in 39 out of the 50 amendments. Where we have not accepted the required amendment, we have reviewed the relevant provisions to ensure the provision is clear. Information explaining Western Power's position in response to each required amendment is provided in this submission.

Summary of AA4 target revenue

86. Taking the ERA's required amendments into consideration, as well as our modified position on a number of items, the proposed transmission and distribution tariff revenue amounts are presented in the following table.

Table 1.3: AA4 target revenue ($ million real, June 2017)

	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal
Transmission tariff revenue	1,687.4	1,816.0	1,741.0
Distribution tariff revenue	6,200.3	5,614.4	5,980.2
Total	7,887.7	7,430.4	7,721.3

87. Our revised AA4 proposal results in a low price impact to the vast majority of customers connected to the network, while enabling Western Power to maintain a safe and reliable network and continue to pursue alternative technology solutions where efficient to do so.

88. We submit that this revised AA4 proposal satisfies the Access Code objective, and that all new facilities investment included in the AA4 opening and forecast RAB satisfies the requirements of the NFIT.

2. Access arrangement revisions submission date

89. This section details Western Power's response to the ERA's required amendment to change the proposed access arrangement revisions submission date for Western Power's fifth access arrangement (AA5, 1 July 2022 to 30 June 2027) proposal.

ERA required amendment 1:

The revisions submission date must be amended to 1 January 2021.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

2.1 The AA5 revisions submission date

90. In the AA4 proposal, Western Power submitted that the AA5 period will commence on 1 July 2022, with the expectation it will be a five-year period concluding on 30 June 2027.

91. Though the ERA does not explicitly state it approves the 1 July 2022 AA5 revision commencement date in its draft decision, it considers *Western Power's proposed target revisions date is equivalent to a five year period*[16] and implies the proposed AA5 target revisions commencement date of 1 July 2022 is acceptable.

92. Therefore we maintain that the target revisions commencement date for the AA5 period is 1 July 2022.

93. The Access Code also requires the access arrangement to specify a *revisions submission date*. This is the date by when the *service provider* must provide its next round of proposed revisions to the access arrangement to *the Authority*. Put simply, this is the date by when Western Power must submit its AA5 revisions to the ERA.

94. The Access Code specifies the revisions submission date must be at least six months prior to the target revisions commencement date. Western Power proposed that the AA5 revisions submission date should be 1 March 2021, 16 months prior to the expected target revisions commencement date for the AA5 period.

95. However, the ERA considers *18 months is the minimum period required to ensure there is sufficient time for review, stakeholder consultation and finalisation of the decision prior to the targeted revisions commencement date*[17], and therefore considers the AA5 revisions submission date should be 1 January 2021.

96. While there is an argument to make the access arrangement review period longer, we consider it advantageous to customers if the revisions submission date is as close as reasonably practicable to the target revisions commencement date. This is because it allows more up-to-date financial and demand/consumption data to be included in the revisions submission, and gives customers (and the ERA) greater certainty that the assumptions made in the initial submission will remain valid during the forthcoming access arrangement period.

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16 Paragraph 46, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
17 Paragraph 52, ibid.

97. Given the review process is designed to determine a reasonable revenue forecast for a five-year period, the more contemporary the information used to underpin the revenue forecast, the more accurate the forecast is likely to be.

98. We propose a submission date 16 months before the commencement date, which allows for the maximum extensions allowed under the Access Code. In our October 2017 AA4 proposal, we submitted a lodgement date of 1 March 2021. However, as this date is a public holiday in Western Australia, Western Power proposes to amend this date to 26 February 2021. The following table outlines the potential review milestones with maximum extensions.

Table 2.1: Proposed AA5 review time line

AA5 determination review milestone	Date with maximum extensions
1. Western Power submits proposed AA5 revisions	Friday, 26 February 2021
2. ERA publishes proposed access arrangement with invitations to submit – maximum 5 business days after revisions submission date	Monday, 8 March 2021
3. Submissions are due a maximum of 30 business days from invitation or 10 business days after issues paper	Thursday, 22 April 2021
4. ERA draft decision published – maximum 94 business days after due date for submissions	Friday, 3 September 2021
5. Western Power submits revised proposed access arrangement – maximum 40 business days after draft decision	Friday, 29 October 2021
6. ERA final decision published – maximum 70 business days after submissions due	Thursday, 10 February 2022
7. Western Power submits amended proposed access arrangement – maximum 40 business days after final decision	Friday, 8 April 2022
8. ERA further final decision published – maximum 30 days after amended proposed AA submission is due	Wednesday, 25 May 2022
9. AA5 period commences a minimum of 20 business days after the further final decision, at the start of the next calendar month	Thursday, 1 July 2022

99. We consider 16 months is sufficient time to complete an access arrangement review. As the ERA explains in paragraph 50 of its draft decision, the AA2 and AA3 review processes took 17 months and 16 months respectively. The AA1 process, which took 22 months, was lengthier due to the complexity of establishing an entirely new access arrangement and a review process that was new for all parties.

100. We expect the current AA4 review process will not require the full 16 months available. Given the relative maturity of the review process we consider the AA5 review can be completed within 16 months. With a view to providing certainty and avoiding price shock, we also believe it is in the interest of customers for Western Power and the ERA to conduct access arrangement reviews in as short a time frame as possible.

101. We therefore propose that 26 February 2021 is an appropriate AA5 revisions submission date.

2.2 The AA4 revisions commencement date

102. As highlighted in paragraph 42 of the ERA's draft decision, the commencement date for the AA4 revisions will be confirmed in the ERA's final decision. The ERA's draft decision is based on Western Power's proposed commencement date of 1 July 2018.

103. Given the ERA's draft decision was not published until 2 May 2018, and a final decision is not expected until late July 2018 (assuming no further extensions are taken by either party), the 1 July 2018 AA4 start date is no longer practicable.

104. We therefore submit that the access arrangement revisions for the AA4 period should come into effect on **1 November 2018**. Assuming the ERA's further final decision will be made in September 2018, this provides for the one month minimum prescribed period for the revised access arrangement to come into effect following the ERA's decision.

3. Total revenue requirement

105. This section details Western Power's response to the ERA's required amendments to the total revenue requirement for the AA4 period. This includes:

- the form of price control
- charges for non-revenue cap services
- distribution and transmission target revenue and smoothing profile.

3.1 Form of price control

ERA required amendment 2:

Western Power must amend its proposed revised access arrangement to:

- remove the correction factor for under or over-recovery of target revenue for prior periods from the price control formula; and
- add a requirement that the forecast customer numbers, energy volumes and any other charging parameters for each reference service must be consistent with the demand forecast approved with the access arrangement decision.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

106. In its AA4 proposal, Western Power submitted that the current revenue cap form of price control be retained for the AA4 period.

107. Specifically, we proposed to:

- retain the revenue cap form of price control and building block method to calculate target revenue
- use a nominal post-tax weighted average cost of capital to calculate the return on the capital base
- expand the revenue cap formula for the annual price list to include an adjustment for the annual update to the weighted average cost of capital
- set charges for non-revenue cap services on the same basis as for AA3.

108. This is exactly the same form of price control that was in place during the AA3 period and almost identical to the revenue cap form of price control that has been in place since disaggregation of Western Power Corporation in 2006.

109. There are many forms of price control contemplated by the Access Code and by network businesses across Australia, however, most broadly they fall into one of two categories:

- a revenue cap
- a price cap.

110. Put simply, a revenue cap form of price control is where the total amount of revenue required by the network business to provide services is calculated and then fixed (or 'capped') for the access arrangement

period (typically five years). This revenue amount is then contemplated against forecast demand, and network prices are set in order to recover the targeted amount of revenue.

111. Where actual demand varies from forecast in any one year, prices are adjusted in the following year in order to recover the amount of target revenue that has been capped. Where demand is higher than forecast, and therefore the amount of revenue collected is higher than the target, prices are adjusted downwards in the next year so that the network 'gives back' the revenue over-recovery.

112. Similarly, where demand is lower than forecast, prices are increased in the following year so that the network business can collect the revenue under-recovery. Either way, the regulated network business is afforded limited opportunity[18] to 'out-perform' its revenue requirement and increase its profitability.

113. A price cap follows a similar approach whereby the amount of revenue required for an access arrangement period is calculated, and then forecast demand is used to set the network prices required to collect that revenue. However, the fundamental difference with a price cap is that rather than the revenue being fixed, it is the prices that are fixed for the period[19]. The actual revenue a network business can earn will vary depending on actual demand and there is no annual revenue adjustment to account for shortfalls (or over-recovery).

114. A price cap permits network businesses considerable opportunity to out-perform its revenue requirement and increase profitability (as was the case when many eastern-state network businesses operated under price caps), but it also exposes the business to revenue risk if actual demand is lower than forecast.

115. There are subtle variations of these two forms of price control for regulated monopoly businesses, but broadly speaking, most forms of price control will either control revenue or control prices.

116. There are advantages and disadvantages to both the revenue cap and price cap form of price control, and these have been debated at length fairly recently by the Australian Energy Regulator (AER) and network businesses, following the AER's 2013 framework and approach review for the NSW distribution networks. The AER subsequently required all distribution network businesses to move from a price cap to a revenue cap. This brought the distribution network businesses into line with transmission network businesses who were already required to operate under a revenue cap, as mandated under the National Electricity Rules.

117. There are fundamental differences between these two forms of price control in terms of commerciality, risk exposure, certainty of revenue/pricing, profitability and dependence on forecasting capability. This means that a regulated business' approach, range of services, investment profile, debt/credit rating and most aspects of commercial decision making must be tailored according to which form of price control it is under. A change in the form of price control has flow-on effects for many aspects of a business' operations.

118. We consider there is no single access arrangement that could be developed such that it would have the same effect under a price cap or a revenue cap and certainly not one that can be switched seamlessly between the two. Careful consideration of a range of factors must be contemplated before transferring between the two forms of price control. This is evidenced in the AER's framework and approach method, which specifies a form of price control to be applied to the forthcoming regulatory period and affords all parties sufficient time and opportunity to consider how that form of price control impacts its business.

119. Though not explicitly stated, the ERA in its draft decision proposes that Western Power adopts a price cap form of price control.

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18 Typically a revenue cap form of price control will provide incentive mechanisms where a business is rewarded (or penalised) according to service level performance and improving efficiency. However, these rewards and penalties are capped.

19 Again, subject to adjustment for inflation, debt raising costs and movements in prices subject to side constraints.

120. The ERA requires that the current form of revenue cap price control be amended by:

> *removing the correction factor for under or over-recovery of target revenue for prior periods from the price control formula; and*
>
> *requiring the forecast revenue recovery from Western Power's proposed tariffs in each year's Price List to be based on customer numbers and volumes consistent with the demand forecast approved with the AA4 decision.*[20]

121. This change removes the opportunity for Western Power's target revenue to be adjusted for actual demand and requires that prices be constrained to the demand forecasts approved by the ERA. This is a price cap form of price control.

122. The ERA's draft required amendment is the most fundamental change to an access arrangement that can be made. It is an amendment that would require a fundamental change to Western Power's business operations, its view of forecast costs, and the suite of services and tariffs it offers customers. It is not practical to move to price cap regulation at this stage of the access arrangement review process, particularly when the AA4 proposal and its associated services, tariffs and costs have been formed on the presumption a revenue cap form of price control will be maintained.

123. A move to a price cap has not been contemplated by Western Power during the development of its services, investments and tariffs for the AA4 period. Adopting a price cap was not raised with Western Power by the ERA until its draft decision. The ERA had opportunity to fairly raise that it was considering requiring Western Power to fundamentally change its form of price control when it released its Issues Paper[21] in October 2017, however, it did not. Further, the ERA did not engage with Western Power on this fundamental issue at any point during the AA4 review process.

124. Western Power could not have anticipated such a required amendment from submissions made to the ERA. No submission advocated for a price cap.

125. A required amendment that alters the central feature of the access arrangement has come without notice and without an adequate and fair opportunity for Western Power to properly consider it. It comes without adequate reasons, which are required by section 4.27 of the Access Code.

126. The complexities of implementing a price cap are exacerbated further by the fact it is unlikely that the revised access arrangement for AA4 will come into effect until almost 18 months of the five-year AA4 period have elapsed. This means we would be effectively changing price control mid-period. It is unclear whether and how a price cap form of price control can be applied retrospectively to adjust for revenue collected under a revenue cap since the start of the period.

127. As the ERA has not considered the regulatory and business consequences of its draft required amendment, or given Western Power a fair opportunity to consider it, we consider it vital that the ERA revisits its decision on the form of price control and reverts to a revenue cap.

128. We have a number of other concerns relating to the ERA's draft decision on the form of price control. These are discussed in the following sections.

[20] Paragraph 90, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[21] Issues Paper on Proposed Revisions to the Western Power Network Access Arrangement (2017/18 to 2021/22 - AA4), ERA, 31 October 2017.

3.1.1 The ERA has not demonstrated that Western Power's proposal does not satisfy the Access Code objective

129. Section 4.28 of the Access Code requires an assessment of Western Power's proposal and a demonstration of how it does not comply with the Access Code objective and other relevant Access Code requirements:

> *4.28 Subject to section 4.32, when making a draft decision, final decision or further final decision, the Authority must determine whether a proposed access arrangement meets the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) and:*
>
> *(a) if the Authority considers that:*
>
> *(i) the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied — it must approve the proposed access arrangement; and*
>
> *(ii) the Code objective or a requirement set out in Chapter 5 (or Chapter 9, if applicable) is not satisfied — it must not approve the proposed access arrangement;*
>
> *and*
>
> *(b) to avoid doubt, if the Authority considers that the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied, it must not refuse to approve the proposed access arrangement on the ground that another form of access arrangement might better or more effectively satisfy the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable).*
>
> *{Note: The effect of section 4.28 is to make the Authority's decision in relation to a proposed access arrangement a "pass or fail" assessment. The intention is that, if a proposed access arrangement meets the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable), the Authority should not refuse to approve it simply because the Authority considers that some other form of access arrangement might be even better, or more effective, at meeting the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable).}*

130. The Access Code objective is:

> *2.1 The objective of this Code (**"Code objective"**) is to promote the economically efficient:*
>
> *(a) investment in; and*
>
> *(b) operation of and use of,*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*
>
> *{Note: This Code sets out more specific objectives that also apply in relation to the performance of certain functions under the Code, for example, section 6.4 sets out objectives for the price control in an access arrangement.}*

131. Put simply (and as explained in paragraph 22 of the ERA's draft decision), *if the ERA considers the Access Code objective and requirements of chapter 5 are satisfied it must approve the access arrangement. The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5.*

132. We do not consider the requirement permitting the ERA to reject Western Power's access arrangement have been met. The ERA has not established that the revenue cap form of price control proposed by Western Power for the AA4 period does not satisfy the requirements of the Access Code objective.

133. At paragraph 86 the ERA concludes:

> *Based on past experience, the ERA considers Western Power's current price control is not compliant with section 6.4(b) of the Access Code as it has not enabled users to predict the likely annual changes in target revenue during the access arrangement period, and has not been compliant with the requirements of section 6.4(c) to avoid price shocks*.

134. The price control are provisions in an access arrangement which determine target revenue for the AA4 period. For the ERA to be satisfied Western Power's price control does not meet the requirements of the Access Code it must do so on the basis of a finding about the future; it cannot be based on past experience. The ERA provides no basis upon which it finds that sections 6.4(b) and 6.4(c) of the Access Code will not be satisfied in the AA4 period.

135. Insofar as past experience may be relied upon as part of forming a view of the future, the ERA has not provided evidence that sections 6.4(b) and 6.4(c) of the Access Code were not satisfied during the AA3 period. It discusses circumstances that prevailed during that period, and does so incorrectly, but in any event there is no material that demonstrates that users raised any concerns with predicting the likely changes in target revenue or that the price control did not avoid price shocks during the AA3 period. The ERA has not demonstrated that sudden material tariff adjustments occurred, or that any changes in tariffs were sufficiently material or unforeseen that they caused the Access Code objective to not be satisfied.

136. Moreover, the ERA provides no basis upon which it can reasonably reach the conclusion that circumstances that may have existed in AA3 will prevail in AA4.

137. The form of price control proposed by Western Power for the AA4 period is the exact same form of price control in place today. The ERA has determined that a revenue cap with a K-factor adjustment satisfied the Access Code objective and the price control objective in the AA1, AA2 and AA3 periods. The ERA has not demonstrated what is materially different about the AA4 period that suggests this form of price control is no longer appropriate.

3.1.2 The form of price control during the AA3 period satisfied the price control objectives and did not result in price shocks

138. Section 6.4 of the Access Code contains the price control objectives for an access arrangement:

> ***Price control objectives***
>
> *6.4 The price control in an access arrangement must have the objectives of:*
>
> *(a) giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:*
>
> *(i) an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;*
>
> *plus*
>
> *(ii) for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation*

beyond the efficiency and innovation benchmarks in a previous access arrangement;

plus

(iiA) an amount (if any) determined under sections 6.5A to 6.5E;

plus

(iii) an amount (if any) determined under section 6.6;10

plus

(iv) an amount (if any) determined under section 6.9;11

plus

(v) an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);

plus

(vi) an amount (if any) determined under section 6.37A;12

and

(b) enabling a user to predict the likely annual changes in target revenue during the access arrangement period; and

(c) avoiding price shocks (that is, sudden material tariff adjustments between succeeding years.

6.5 The amount determined in seeking to achieve the objective specified in section 6.4(a)(i) is a target, not a ceiling or a floor.

139. In its draft decision, the ERA focuses on sections 6.4(b) and 6.4(c) of the Access Code. The ERA highlights that the increase in average network tariffs during the AA3 period was greater than the forecast rate of inflation (CPI). Based on this:

> *the ERA considers Western Power's current price control is not compliant with section 6.4(b) of the Access Code as it has not enabled users to predict the likely annual changes in target revenue during the access arrangement period, and has not been compliant with the requirements of section 6.4(c) to avoid price shocks.*[22]

140. We acknowledge that prices during AA3 increased above CPI, however, price increases above CPI were approved by the ERA. Perhaps more importantly, the actual price changes that occurred were not materially different from the prices that were approved and published by the ERA on 4 June 2013. This is shown in Table 3.1.

Table 3.1: Comparison of approved and actual average annual price changes during the AA3 period

Financial year	Approved annual average price increases published in the ERA's mid-period variation on AA3, 4 June 2013(1)	Actual annual average price increases during the AA3 period increases(2)
2012/13	n/a	1.45% + CPI
2013/14	2.2%+ CPI	2% + CPI

22 Paragraph 86, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Financial year	Approved annual average price increases published in the ERA's mid-period variation on AA3, 4 June 2013(1)	Actual annual average price increases during the AA3 period increases(2)
2014/15	2.1%+ CPI	2.05% + CPI
2015/16	2.5%+ CPI	2.6% + CPI
2016/17	2.5%+ CPI	-0.8% + CPI

Notes:

(1) Decision: Variation to Western Power's Access Arrangement for 2012/13 to 2016/17, 4 June 2013[23].

(2) These values are as per Table 1 in the ERA's draft decision, presented to show the price change in relation to CPI, for consistency.

141. As can be seen in Table 3.1, the price increases that materialised were very similar to those approved by the ERA and subsequently communicated to users in June 2013. We therefore consider the form of price control that gave rise to these price changes was consistent with section 6.4(b) as the price changes were consistent with those forecast, and therefore users would have been able to predict the likely changes in annual revenue during the access arrangement period.

142. The ERA appears to have formed the view that prices need only increase by CPI, based on the statement:

> *For example, the ERA's final decision for AA3, published on 5 September 2012, anticipated average charges over the AA3 period would increase broadly in line with the Consumer Price Index (CPI).*[24]

143. It is unclear why the ERA is referring to the final decision for AA3. The ERA's 5 September 2012 final decision was to not approve the access arrangement. The subsequent further final decision (and June 2013 mid-period variation) superseded the final decision.

144. With regard to the objective to avoid price shocks under section 6.4(c) of the Access Code, we submit that the ERA has not provided sufficient evidence that price changes during the AA3 period were sudden or material.

145. We acknowledge the ERA's concerns over the initial 2013/14 Price List.[25] As highlighted by the ERA, the 2013/14 proposed price increases were due to the TEC being materially higher than originally forecast, demand being materially lower than forecast, and revenue recovery being below forecast over 2012/13. It is not clear that any of these issues would have been avoided had a price cap form of price control been in place at the time. The demand and TEC changes were significant enough that the ERA re-opened the access arrangement. Had a price cap been in place, it is likely Western Power would have requested to re-open the access arrangement for the same reasons.

146. The decline in demand (and therefore revenue) was not solely a Western Power issue. Network businesses and other energy forecasters around Australia were equally impacted by the sudden decline in energy volumes. In our view, a change in circumstances of this magnitude would not be a price shock issue, but a matter better dealt with by the access arrangement mid-period revision provisions in the Access Code. This is the approach the ERA took in re-making the AA3 decision and Western Power considers this would have applied under either a price or revenue cap form of price control.

23 http://www.erawa.com.au/cproot/11386/2/20130604%20D106966%20-%20Decision%20to%20amend%20price%20control%20in%20Western%20Power%20s%20access%20arrangement%20AA3.pdf

24 Paragraph 83, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

25 Paragraph 83, ibid.

3.1.3 Western Power already takes measures to avoid price shocks under the current form of price control

147. As discussed above, the ERA's primary concern appears to be managing the volatility of prices between years and access arrangement periods, with a view to avoiding price shocks. We agree avoiding price shocks is one of the objectives in section 6.4, and have applied already-existing provisions under the current form of price control to achieve this. These provisions were actually proposed by Western Power during the AA3 review and subsequently accepted by the ERA.

148. During the AA3 review, Western Power proposed an amendment to give it the flexibility to set prices under the revenue cap to manage price volatility and perform revenue smoothing. We amended clause 6.5.3 of the access arrangement so that prices do not need to be set to exactly recover the revenue target, but can be set such that the prices do not recover more than the revenue cap. That is, prices can under-recover against the revenue target.

149. This provision was designed to help Western Power manage the impact of factors outside of its control such as the take up of PV systems (which can lead to lower network demand) and costs associated with the TEC[26]. It allows Western Power the ability to recover revenue over multiple years rather than sticking to the formula of a revenue cap.

150. The ERA refers to Western Power's use of this provision in paragraph 85 of its draft decision, whereby we deferred recovery of $29.7 million of revenue for collection in future years in order to mitigate price impacts on customers.

151. This provision was also used in 2014/15 to ensure price outcomes matched the AA3 approved price path as close as reasonably possible. Western Power proposes to retain this provision in AA4 and continue the practice of 'self-moderating' price increases.

3.1.4 The form of price control does not prohibit development of efficient tariffs or customer connections

152. Another concern the ERA cites about the current form of price control is:

> *Western Power has made little change to its cost allocations or tariff structures since the current regulatory framework commenced. Most users continue to be charged based on energy volumes.*[27]

153. This finding is not supported by any material and is not relevant to the form of price control. A revenue cap form of price control does not prohibit a network user developing new tariff structures and services that customers desire, nor does it provide any incentive not to do so. The ERA provides no basis for its conclusion that it may. The ERA presumably seeks to establish that the revenue cap leads to the identified behaviour which allows the conclusion the Access Code objectives are not being met, but there is no discussion or substantiation of such a finding.

154. Western Power has introduced and successfully implemented demand and time of use tariffs while under a revenue cap form of price control. Further, we have proposed new time-of-use and/or demand reference services for the AA4 period, as well as modifying other services based on feedback from customers. We have also proposed improvements to connection processes and cost allocation, all under a revenue cap regime.

[26] Tariff Equalisation Contribution, which is determined and gazetted by State Government, and recovered via Western Power's network tariffs and passed through to Horizon Power.

[27] Paragraph 87, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

155. We also reject the ERA's finding that the revenue cap may be a disincentive to encourage the connection of new customers. This finding is not supported by any material. The ERA presumably seeks to establish that the revenue cap leads to the identified behaviour which allows the conclusion the Access Code objectives are not being met, but there is no discussion or substantiation of such a finding

156. Western Power is committed to connecting customers with electricity. We recognise that new connections can sometimes be challenging due to the configuration and unconstrained nature of the network, however, the development of the Generator Interim Access solution is one way in which Western Power is attempting to connect customers as soon as is practicable.

157. Additionally, we have been working with customers in the Eastern Goldfields region to unlock any spare capacity that may be available. For example some businesses are able to take advantage of additional capacity overnight. Western Power is pursuing these options to assist customers, while being under a revenue cap.

158. Therefore, while we agree with the ERA that network businesses should encourage the connection of new customers and offer services that meet user preferences where possible, we do not consider the current form of price control is a barrier to this. The ERA has not established that it is.

3.1.5 Western Power is not immune to demand risk

159. One of the concerns raised by Synergy in its public submission, and echoed by the ERA in its draft decision, *is that Western Power's current price control puts all demand risk on users.*[28]

160. The ERA then concludes:

> *If Western Power was exposed to demand risk, which could be increases or reductions in demand compared to forecast, it would develop more efficient tariffs, encourage the connection of new customers and offer services that meet user requirements and benefit Western Power through increased revenue, reduced costs or a combination of both.*[29]

161. While a revenue cap form of regulation places a degree of demand risk on users, as discussed earlier, there are sufficient regulatory checks as well as Western Power's own actions that mitigate this risk such that price increases are constrained and/or revenue deferred to ensure customers are not severely impacted.

162. Further, it is incorrect to assume that Western Power is immune from demand risk. As has been widely discussed in the Australian energy sector, changing technology, energy efficiency and distributed energy resources are all impacting the way customers use electricity networks. The long-term sustainability and profitability of conventional network models is being challenged.

163. This demand risk places an incentive on network businesses to pursue innovative services such as microgrids, standalone power systems, locational pricing and time of use tariffs. Network businesses are no longer natural monopolies and they are being forced to respond to a market that is changing around them.

164. To assume a price cap form of price control is required in order to drive the customer-focused behaviours the ERA desires, and thereby presume a revenue cap form of price control inhibits such behaviour, is unfounded. The ERA's conclusions are not supported by any material and are speculative. It does not establish how these findings are relevant to approving a price control that exposes Western Power to demand risk through a price cap. It provides no analysis of the relationship between its findings and section 6.4 of the Access Code.

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28 Paragraph 82, *Draft Decision on Proposed Revision to the Access Arrangement for the Western Power Network*, ERA, May 2018.

29 Paragraph 88, ibid.

165. It is worth noting that all distribution network businesses under the AER's jurisdiction have recently been moved to a revenue cap form of price control. We are not aware of any evidence that suggests these businesses are no longer subject to demand risk and that the change of price control has been to the detriment of customers.

3.1.6 The form of price control should not be considered in isolation

166. As previously discussed, the form of price control has a considerable influence over other elements of an access arrangement and the way a business operates. With regard to the specifics of an access arrangement, the form of price control has a direct bearing on:

- **the suite of incentive and adjustment mechanisms** – mechanisms such as the GSM and SSAM, which are essential under a revenue cap regime, have less power under a price cap regime. This is because the opportunity to out-perform or under-perform against target revenue already provides an incentive to improve service and/or reduce costs. If the form of price control changes, these incentives should also be carefully designed to ensure they drive appropriate behaviours
- **the regulated rate of return** – a change in price control changes the risk profile of a business. As highlighted by the ERA, a change in price control can place greater demand risk on a network business. Therefore the WACC should be calculated so that it reflects the greater risk associated with investing in a business under a price cap (or equivalent) form of price control
- **demand and customer number forecasts** – a price cap form of price control provides an incentive for network businesses to under-estimate demand and for regulators to over-estimate demand.

167. These are just some of the considerations that must be factored into the decision of what form of price control to apply. The ERA's draft decision provides no evidence that these and other elements have been factored into its recommendation to divert from the current revenue cap price control.

168. We submit that if the form of price control is changed, it requires reassessment of the entire AA4 proposal by both the ERA and Western Power.

3.1.7 Revenue cap versus price cap

169. Finally, taking all of the above into consideration, there remains a question as to which form of price control will best achieve the objectives of section 6.4 and the Access Code objective.

170. Changing the form of price control should be subject to a detailed, timely and fulsome consideration of the issue and its practicability. We therefore do not intend to debate which form of price control is most suitable.

171. Rather, we would like to highlight that significant work was recently conducted by the AER and the network businesses within its jurisdiction to consider the advantages and disadvantages of revenue and price caps.[30] Among its many conclusions about the application of price caps, the AER found that:

a) there was no evidence of efficient pricing as a result of a price cap

b) the theoretical advantages have not eventuated in practice

c) placing volume and revenue recovery risk on to the DNSP has resulted in DNSPs over-recovering against the revenue allowance in nearly all cases.

[30] https://www.aer.gov.au/system/files/AER%20-%20Stage%201%20Framework%20and%20approach%20-%20NSW%20distributors%20-%20March%202013_2.doc

172. A decision by the ERA to change the form of price control should consider whether moving to a price cap would achieve the outcomes the ERA is seeking to any greater extent than the current form of price control.

3.1.8 The ERA's required amendment

173. The ERA requires its amendments in order to satisfy the objectives in sections 6.4(b) and 6.4(c) of the Access Code. It considers this will be achieved by ensuring demand risk is faced by Western Power rather than users.

174. However, apart from the speculative matters considered in paragraph 88, the ERA provides no reasons for reaching this view.

175. The ERA spends some time explaining why it does not approve Western Power's proposed revenue cap but provides no reasons why it requires the amendment it does. There is no discussion of how these required amendments meet sections 6.4(b), 6.4(c), and also section 6.4(a) of the Access Code.

176. On the ERA's own analysis, placing demand risk on Western Power puts Western Power's revenue at risk. Indeed this is a purpose of the proposed amendments. However, no consideration is given to section 6.4(a) and no reasons are given for why the ERA gives primacy to section 6.4(b) and 6.4(c) over section 6.4(a).

3.2 Non-revenue cap services

ERA required amendment 3:

A clause should be added to 5.12 of the proposed revised access arrangement stating that prices for access applications will be consistent with the applications and queuing policy and prices for extended metering services will be consistent with the model service level agreement.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

177. The ERA's amendment ensures that the current approach to pricing these services is explicitly specified in the access arrangement. Western Power can see the merit in including this reference and has made the necessary amendment in section 5.1.2 of the revised proposed access arrangement.

3.3 Target revenue and smoothing

ERA required amendment 4:

The proposed revised access arrangement values for TR_t and DR_t must be amended to reflect the ERA's draft decision of target revenue. Western Power should review its smoothing profile to avoid price shocks and ensure the final year reduces the likelihood of price shocks in the next access arrangement period.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

178. This required amendment contemplates two broad issues:

1. the amount of revenue Western Power collects over the AA4 period and
2. setting the transmission tariff path to mitigate against price shock.

179. Western Power accepts the principle of the ERA's required amendment in that target revenue will be revised in response to the draft decision, and that the profile to collect target revenue should aim to avoid price shocks. However, we have not adopted the amendment exactly as required.

180. With regard to the revenue collection in AA4, due to modifications elsewhere in this revised AA4 proposal, we have calculated different values for TR_t and DR_t to those contained in the ERA's draft decision.

181. The transmission and distribution target revenue amounts in this revised AA4 proposal are set out in the following tables.

Table 3.2: Revised proposal forecast transmission change in average charges

Transmission revenue	2017/18	2018/19	2019/20	2020/21	2021/22
Unsmoothed revenue ($million real at 30 June 2017)	339.7	355.5	372.7	405.0	432.2
Smoothed revenue ($million real at 30 June 2017)	284.3	302.7	348.6	384.0	421.4
Energy transported (GWh)	17,698	17,663.0	17,628.0	17,502.0	17,309.0
Average charge ($'000/MWh)	16.4	18.5	20.9	23.6	26.7
Annual % change	0.00%	13.00%	13.00%	13.00%	13.00%

Table 3.3: Revised proposal forecast distribution change in average charges

Distribution revenue	2017/18	2018/19	2019/20	2020/21	2021/22
Unsmoothed revenue ($million real at 30 June 2017)	1,406.1	1,148.5	1,140.9	1,116.4	1,144.9
Smoothed revenue ($million real at 30 June 2017)	1,193.5	1,192.3	1,204.4	1,197.2	1,193.2
Energy transported (MWh)	13,691	13,656.0	13,505.0	13,276.0	13,083.0

Distribution revenue	2017/18	2018/19	2019/20	2020/21	2021/22
Average charge ($'000/MWh)	88.8	91.4	94.2	97.0	99.9
Annual % change	0.00%	3.00%	3.00%	3.00%	3.00%

182. With regard to the challenge of avoiding (or at least mitigating) price shock for transmission customers, we have looked at further options to address the transmission price path issue.

183. The transmission price path issue is the result of the smooth tariff path that was set by the ERA for transmission tariffs for the AA3 period. During the AA3 period, transmission target revenue was materially lower than during the AA2 period. This meant a price decrease for transmission customers.

184. Rather than have a sharp price decrease in the first year of the AA3 period to match the target revenue reduction, followed by flat prices thereafter, the ERA's preferred option was to have a 'smooth' tariff path of even price decreases in each year of the period. This meant that transmission tariffs at the beginning of the AA3 period were set higher than target revenue, before declining each year such that by the end of the period, tariffs are substantially lower than target revenue.

185. Transmission network tariffs have decreased on average by seven per cent (nominal) per year over AA3.

186. This declining tariff path leads to a significant issue as we transition into the AA4 period. Prices have now declined so far below target revenue that even though the total transmission revenue across the entire AA4 period is only around six per cent more than that in AA3, there would need to be sharp price increases to recover the target revenue amount.

187. Western Power recognised this issue in its AA4 proposal, and went to considerable lengths to avoid price shock for transmission customers. This included changing the timing of transmission and distribution revenue collection such that transmission tariff increases would be capped at 10 per cent per year.

188. We proposed several options to address the impact of the transmission tariff path.[31] However, the ERA has chosen not to adopt any of the options we put forward.

189. In its draft decision, the ERA states:

> *The ERA considers there are a range of revenue smoothing profiles that would meet the Access Code requirement to avoid price shocks, which Western Power should consider. The ERA requires Western Power to amend its target revenue to be consistent with the draft decision but should review the smoothed target revenue to reduce the likelihood of price shocks in the next access arrangement period.*[32]

190. There is no simple solution to the transmission tariff path issue, and the ERA has provided no advice on the range of revenue smoothing profiles it considers would avoid price shock. Indeed, the transmission revenue profile put forward by the ERA in its draft decision results in price increases of 12.43 per cent per year (in real terms).

191. In addition, the ERA has made clear that the concept of adjusting the timing of the distribution deferred revenue amounts to compensate Western Power for any shortfall in transmission revenue is not going to be accepted. We acknowledge this decision though we note it removes the ability to creatively solve a fairly complex problem.

[31] Four practicable options were submitted for consideration by the ERA in Attachment 10.8 of the AA4 proposal.

[32] Paragraph 118, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

192. Stakeholders also seem divided on this issue. During the ERA's public consultation process, several stakeholders recognised that Western Power had made a valid attempt to address price shock via its proposal to defer some transmission revenue and bring forward distribution revenue, however there was no consensus on what the best solution is.

193. We have therefore modelled several further potential transmission tariff paths, and we present them for consideration. While we have identified a preferred option for the purpose of this AA4 revised proposal, we welcome engagement with the ERA on the transmission tariff issue and are happy to work with the ERA to finalise a smoothing profile that meets the ERA's and transmission customers' requirements.

194. Note that all price movements presented in the following sections are in nominal terms.

3.3.1 Option 1 - equal price changes

195. Applying the default smoothing approach, that is seeking equal changes in price each year, results in the following pricing outcomes for transmission customers.

Table 3.4: Transmission tariff path option 1 – equal price changes

Option 1	2017/18	2018/19	2019/20	2020/21	2021/22
Price change (nominal)	0.00%	18.13%	18.13%	18.13%	18.13%

196. This option allows Western Power to fully recover the revenue requirement. However it is likely to represent price shock to customers. In addition, the difference in final year smoothed revenue, when compared to unsmoothed revenue is $77.4 million. This represents 16.33 per cent of unsmoothed revenue, which means it is highly likely there will need to be a significant price change in AA5 to deal with this difference.

3.3.2 Option 2 – step change

197. The simplest way to ensure final year revenues (smoothed and unsmoothed) are aligned is to include a step change in year one[33]. This is the approach the AER favours in its decisions. The remaining years of the access arrangement period can then be set to relatively flat price changes, which means there will likely be less risk of price shock when transitioning into the following period.

198. The step change option is represented in the following table.

Table 3.5: Transmission tariff path option 2 – step change

Option 2	2017/18	2018/19	2019/20	2020/21	2021/22
Price change (%)	0.00	49.66	2.50	2.50	2.50

199. While this option meets the objective of avoiding price shock during the transition to the AA5 period (0.07 per cent or $0.31 million variance), the 49 per cent increase in 2019 is very likely to constitute price shock.

3.3.3 Option 3 – equal changes with deferred revenue (selected option)

200. Option 3 adopts a smooth price path, however it includes deferring an amount of transmission revenue. Tariffs are set such that the AA4 final year revenues are better aligned with building block revenue so as to

33 Note that due to the delays in the AA4 process, 'year 1' will actually be around 18 months into the period.

help avoid price shock into AA5. The balance of the revenue requirement is then added to the already-existing deferred revenue account for transmission.

201. Unlike the preferred option in the AA4 proposal, this does not involve bringing forward collection of distribution revenue to offset the transmission revenue decrease

202. This option is presented in the following table.

Table 3.6: Transmission tariff path option 3 – equal changes with deferred revenue

	2017/18	2018/19	2019/20	2020/21	2021/22
Price change (%)	0.00	13.00	13.00	13.00	13.00

203. While this option meets the objective of ensuring the final year revenue aligns (2.49 per cent or $11.8 million variance), Western Power would need to defer $171 million of transmission revenue to the AA5 period.

204. While this is not an ideal outcome, in the interests of resolving this issue for transmission customers, Western Power is willing to explore deferred recovery of this transmission revenue and, if required, explore the need for Access Code changes to be made to ensure the recovery of this deferred revenue above the amounts already included from AA2.

205. Of the three options presented in this revised AA4 proposal, Option 3 is the one Western Power selects for the purposes of this submission. However, we welcome input from the ERA, transmission customers, and other interested stakeholders on what the most appropriate solution might be, and whether a smooth tariff path is the most efficient and economic outcome in all cases.

3.4 Revised AA4 target revenue

3.4.1 Tariff Equalisation Contribution

206. Under sections 6.37A and 7.12 of the Access Code, revenue amounts gazetted by the Government may be added to Western Power's distribution revenue target. On 29 May, values for TEC were gazetted[34] for the remainder of the AA4 period.

207. In accordance with the gazetted values, Western Power has updated its AA4 TEC values to the following:

Table 3.7: Forecast TEC for the AA4 period, AA4 revised proposal ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
TEC	167.0	175.0	162.0	157.0	161.0

208. In the initial proposal, TEC was forecast to be as per the following:

Table 3.8: Forecast TEC for the AA4 period, AA4 proposal ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
TEC	167.0	198.0	162.0	157.0	161.0

[34] Page 1746, *Western Australian Government Gazette, No. 78,* 29 May 2018.

3.4.2 AA4 target revenue

209. Taking into consideration the ERA's draft decision and Western Power's position on each of the ERA's required amendments to target revenue, the revised AA4 target revenue amounts are presented in the following tables.

Table 3.9: AA4 transmission target revenue ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Operating expenditure	95.7	88.0	89.9	94.4	96.5	464.6
Depreciation	54.9	63.3	72.5	83.1	89.8	363.6
Redundant assets /Accelerated depreciation	0.0	0.0	0.0	0.0	0.0	0.0
Deferred revenue recovery	4.7	4.8	4.9	5.0	5.1	24.5
Tax payable	0.0	0.0	4.8	37.9	59.1	101.7
Less value of imputation credits	0.0	0.0	-1.9	-15.1	-23.6	-40.7
Return on assets	190.7	196.9	207.4	218.8	225.6	1,039.4
Return on working capital	1.1	1.5	1.5	1.9	2.3	8.3
IAM revenue adjustment	-34.1	0.0	0.0	0.0	0.0	-34.1
SSAM revenue adjustment	13.6	0.0	0.0	0.0	0.0	13.6
Unforeseen events revenue adjustment	4.7	0.0	0.0	0.0	0.0	4.7
Technical rule change revenue adjustment	0.0	0.0	0.0	0.0	0.0	0.0
D-factor revenue adjustment	0.0	0.0	0.0	0.0	0.0	0.0
GSM revenue adjustment	13.4	14.3	14.5	9.8	18.6	70.5
K-factor adjustment	1.3	0.0	0.0	0.0	0.0	1.3
Transmission target revenue for revenue cap services (unsmoothed)	346.0	368.7	393.6	435.6	473.4	2,017.4

Table 3.10: AA4 distribution target revenue ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Operating expenditure	297.7	278.4	285.0	299.8	308.2	1,469.1
Depreciation	155.9	178.5	189.1	188.5	185.0	897.0
Redundant assets/accelerated Depreciation	4.4	7.2	4.6	0.0	0.0	16.2
Deferred revenue recovery	37.5	38.2	38.9	39.6	40.4	194.6
Tax payable	104.2	101.1	121.1	91.1	89.6	507.1
Less value of imputation credits	-41.7	-40.4	-48.4	-36.4	-35.9	-202.8

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Tariff equalisation	167.0	198.0	162.0	157.0	161.0	845.0
Return on assets	356.9	378.1	399.7	423.1	439.5	1,997.3
Return on working capital	7.3	6.9	7.1	7.2	7.5	36.0
IAM revenue adjustment	-6.0	0.0	0.0	0.0	0.0	-6.0
SSAM revenue adjustment	245.7	0.0	0.0	0.0	0.0	245.7
Unforeseen events revenue adjustment	14.5	0.0	0.0	0.0	0.0	14.5
Technical rule change revenue adjustment	0.0	0.0	0.0	0.0	0.0	0.0
D-factor revenue adjustment	8.9	0.0	0.0	0.0	0.0	8.9
GSM revenue adjustment	42.4	45.2	46.0	30.9	58.8	223.3
K-factor adjustment	37.2	0.0	0.0	0.0	0.0	37.2
Distribution target revenue for revenue cap services (unsmoothed)	1,432.0	1,191.1	1,205.1	1,200.8	1,254.2	6,283.1

4. Forecast operating expenditure

210. This section details Western Power's response to the ERA's required amendments to forecast operating expenditure for the AA4 period.

ERA required amendment 5:

The proposed revised access arrangement must be amended to reflect the forecast operating expenditure set out in Table 31 *[of the draft decision]*.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

211. In its AA4 proposal, Western Power submitted it would require $1,805 million in operating expenditure over the AA4 period. This was $696 million lower than approved in AA3, and $584 million lower than actual opex incurred over the AA3 period.

212. We estimated our opex using the same method that applied during AA3 – the base-step-trend method[35]. This method:

- uses the revealed cost from the most recent audited year of financial statements – the base year
- removes non-recurrent costs from the base year
- removes indirect costs from the base year as these are forecast separately
- adjusts the base year for step changes in recurrent opex
- applies network growth factors
- applies any efficiency dividend
- adjusts the resulting opex for in-period non-recurrent opex
- applies labour cost escalation factors.

213. We also used this method to forecast total indirect costs, which were then allocated between capex and opex based on the proportion they attract indirect costs in each year.

214. Section 6.40 of the Access Code provides the test for the recovery of opex from our customers:

> *Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.*

215. Efficiently minimising costs is defined in the Access Code as:

> *… the service provider incurs no more costs than would be incurred by a prudent service provider, acting efficiently in accordance with good electricity industry practice seeking to achieve the lowest sustainable cost of delivering services, and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services.*

35 This is also referred to as the revealed cost method, and in AA3 we referred to it as the base-year roll forward method.

216. It is in this context we do not accept the ERA's required amendment to reduce our forecast opex from $1,805 million to $1,695 million. We consider that the ERA's opex forecast is lower than what would be incurred by a service provider efficiently minimising costs. Moreover, the ERA has made many of its reductions using an assessment method that is incompatible with the base-step-trend method.

217. The ERA's draft decision reduces forecast opex by $110 million, or 6 per cent, on the following basis:

- the ERA applies a $6.3 million reduction to the base year
- the ERA applies a $2.2 million additional negative step change made on the assumption metering replacement volumes were overestimated
- the ERA removes network growth escalation from our opex and indirect cost forecasts in its entirety
- the ERA removes all non-recurrent costs with the exception of regulatory review costs. The ERA excludes:
  - $28.3 million to complete the Business Transformation Program
  - $5.1 million to implement the State Government energy market reform program related to Western Power's functions as a transmission and distribution network service provider

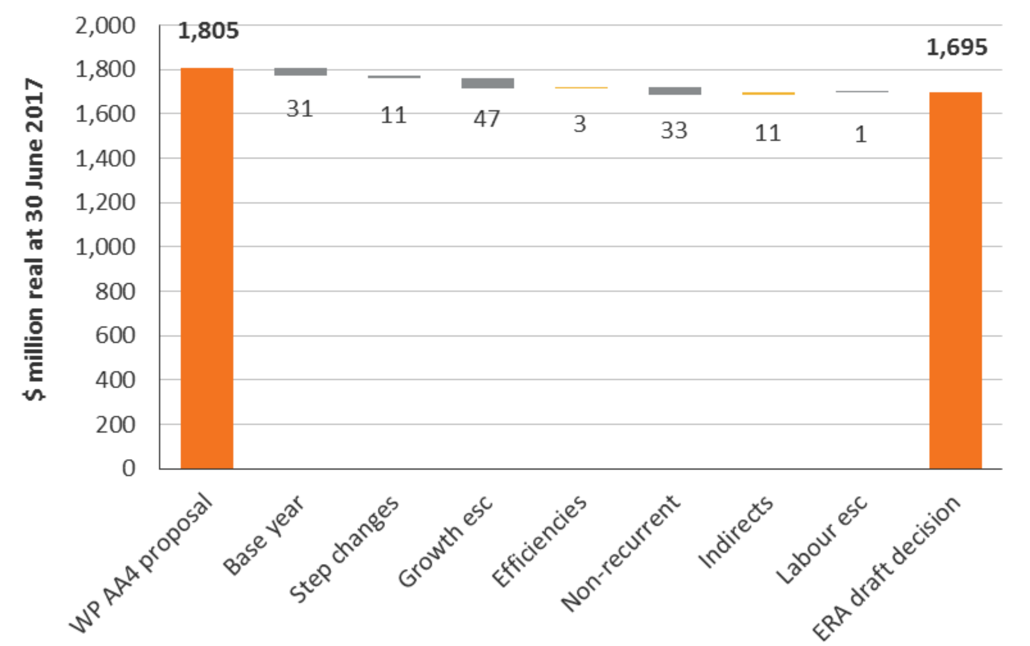
  but includes:
  - $1.1 million for the ERA's AA4 and AA5 review processes.

218. The ERA's draft decision is shown in Table 4.1 and is presented in comparison to Western Power's initial AA4 proposal in Figure 4.1.

Table 4.1: ERA Draft decision opex adjustments ($ million real, June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Efficient base year	311.3	311.3	311.3	311.3	311.3	311.3	1,556.6
Step changes		-7.2	-7.2	-7.2	-7.2	-7.2	-36.0
Total recurrent opex		304.1	304.1	304.1	304.1	304.1	1,520.6
Network growth escalation		-	-	-	-	-	-
Efficiency dividend		-3.0	-6.1	-9.0	-12.0	-14.9	-45.0
Non-recurrent opex		0.5	-	-	-	0.5	1.0
Expensed Indirect costs		41.8	37.6	35.7	42.6	42.2	200.0
Labour cost escalation		1.2	2.3	3.6	5.1	6.7	18.9
Regulated revenue cap opex		**344.6**	**338.0**	**334.4**	**339.9**	**338.6**	**1,695.5**

Figure 4.1: Comparison of ERA draft decision forecast operating expenditure ($ million real, June 2017) to Western Power's draft submission



219. Western Power's consideration of each of the ERA's opex adjustments is presented in the following sections.

4.1 Recurrent base year

220. The ERA's technical consultant (GHD) undertook a benchmarking exercise to assess Western Power's opex forecast against a benchmark efficient service provider. GHD found that:

> *…based on the benchmarking rankings for Western Power, the efficient range for total annual OPEX compared to a hypothetical combined SA Power Networks/ElectraNet electricity entity is between $368 million and $379 million.*[36]

221. Based on this benchmarking, the ERA concludes:

> *… Western Power's proposed base operating expenditure for AA4 of $357.6 million (recurrent network base costs of $317.6 million plus indirect costs of $40 million) is below the predicted efficient costs … Western Power's proposed expenditure for AA4 is at the level that would be incurred by a service provider efficiently minimising its costs.* [37]

222. The ERA also states that:

> *If the ERA considers the Access Code objective and requirements of chapter 5 are satisfied it must approve the access arrangement. The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5.*[38]

[36] Page 228, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.
[37] Paragraph 180, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
[38] Paragraph 22, ibid.

223. It is evident in the draft decision that the ERA (and GHD) concludes that Western Power's proposed base year opex is at a level that would be incurred by a service provider efficiently minimising costs, thereby meeting section 6.40 of the Access Code and the Access Code objective. Despite this, the ERA has made a further adjustment to the base year of $6.3 million per annum.

224. The $6.3 million reduction is based on advice provided by GHD, who conducted a line-by-line (bottom-up) assessment of Western Power's AA4 opex forecasts by regulatory category.[39] GHD compared each of the regulatory category forecasts to the forecast capex program and recommended that the ERA:

> *…do not accept maintaining OPEX levels for SCADA & Communications at the base year levels for transmission asset during AA4, given the substantial asset replacement program proposed for these networks. We consider that it would reasonable to expect that there would be a CAPEX/OPEX trade-off between the new assets and their lower maintenance requirements. We have proposed a nominal 50% reduction in the OPEX forecast for SCADA & Communications.*[40]

225. This recommendation has the effect of reducing supervisory control and data acquisition (SCADA) and Communications opex by $6.3 million, or 50 per cent.

226. This type of bottom-up assessment is incompatible with a top-down forecasting approach. It is not appropriate to make regulatory category level adjustments to an expenditure forecast that has not been developed using a bottom-up approach. This is particularly relevant where the regulator has already used top-down analysis (including benchmarking analysis) to determine that the top-down forecast is efficient.

227. Western Power engaged a technical expert (ACIL Allen) to assess the appropriateness of the ERA's use of a bottom-up assessment to apply reductions to a top-down forecast. ACIL Allen provides the following expert opinion:

> *…the ERA should not reject Western Power's proposed base opex given that it has concluded that it is efficient. Furthermore:*
>
> - *The ERA approves a total level of capex for Western Power for the AA4 period. Western Power can then invest in its network to best meet its objectives during the AA4 period.*
> - *If Western Power redirects part or all of the capex for SCADA to other projects during the AA4 period, the ERA can be satisfied that it is an appropriate decision to ensure economically efficient investment in the network. ERA's consultant advised that:*
>
>   > *… Western Power's governance policies and processes and procedures provide a good basis for governance of investment decisions and project delivery, and that Western Power addresses the principles of good governance well. GHD also found that the application of the policies, processes and procedures was in accordance with the relevant standards and guidelines.*
>
> - *The operating and maintenance expenditure in each cost category does not change to the same extent during the access arrangement period. While the portfolio effect is that the operating and maintenance expenditure tends to be relatively consistent from year to year, expenditure on some assets will increase as they age and the expenditure on other assets will decrease as they are replaced. If the ERA singles out operating and maintenance expenditure in one cost category that may decrease during the access arrangement period, then it should also single out operating and maintenance expenditure in other cost*

[39] Paragraph 175, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[40] Page 224, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

> *categories that will increase during the period. This becomes a bottom up approach, which is inconsistent with the revealed cost approach that the ERA has adopted.*[41]

228. In addition, we note the AER states:

> *Our decision does not set the business' actual operating budget over the access arrangement period. We assess whether opex in aggregate is sufficient to satisfy the opex criteria, not the increases or decreases of individual opex activities. We do not determine what opex activities a network business should undertake or how much it should spend on particular categories 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, total opex varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects. To the extent they do not offset each other, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year-to-year, by continually re-prioritising its work program, as would be expected in a competitive market.*[42]

229. It is for these reasons we have not accepted the ERA's proposed base year reduction.

230. Western Power does, however, propose one minor alteration to the efficient base year to correct an allocation error made when analysing the 2016/17 revealed costs.

231. We have identified that $2.4 million of the 2016/17 revealed costs allocated to the Electricity Market Review (EMR) project were actually recurrent costs, and not non-recurrent costs as originally assumed. While the EMR project is non-recurrent, $2.4 million of the costs incurred were for permanent Western Power employees who were time-sheeting to the EMR project. These employees will continue to work for Western Power during the AA4 period (albeit not necessarily on the EMR project) and therefore the costs associated with those employees are recurrent. The $2.4 million should therefore be included in the base year. On this same basis, $1.1 million has been removed from the EMR non-recurrent network costs forecast.

232. Western Power's revised proposed AA4 base year opex is $320 million. The revised proposed AA4 base year opex remains below the predicted efficient costs as noted by the ERA, we therefore consider that our revised proposed AA4 base year opex reflects the costs that would be incurred by a service provider efficiently minimising costs.

4.2 Step changes

4.2.1 Business Transformation Program

233. In the AA4 proposal, we estimated a $5 million recurrent negative step change, which would apply from 2017/18. This reflects the efficiencies relating to the Business Transformation Program (BTP).

41 Page 11, *Operating Expenditure Expert Report*, ACIL Allen, June 2018. Footnotes have not been included in quoted text.

42 *Draft Decision Attachment 7: Operating Expenditure, AusNet Services – Access Arrangement 2018-22*, AER, 6 July 2017.

234. However, the ERA has removed non-recurrent costs associated with the BTP from the AA4 opex forecast on the basis that *Western Power has identified the above initiatives as being completed with the non-recurrent expenditure, it is not clear how any savings from the final element of the business transformation program during 2017/18 have been incorporated in Western Power's forecast operating expenditure.*[43]

235. In the AA4 proposal, we clearly articulated that the $5 million recurrent negative step change was linked to the successful completion of the BTP.

236. This is evidenced by the ERA's technical consultant stating:

> *The Western Power AA4 OPEX proposal includes consideration of projected cost savings **that will be achieved through the BTP**, through both a $5 M per annum reduction for projected efficiencies in vegetation and overtime management and a 1% per annum efficiency dividend based on initiatives commenced in AA3 that will continue to reduce operating costs during AA4. [emphasis added]*

237. Moreover, GHD states:

> *We recognise that the BTP has been accepted as an approved business-as-usual activity during AA3, and that the annual expenditure on this program has been previously accepted as reasonable in the audited 2016/17 regulated financial statements.*
>
> *Therefore, we accept that the projected costs to complete the program during 2017/18 are consistent with previous expenditure, and that the expenditure is justified in supporting the cost reduction initiatives included in the Western Power AA4 OPEX proposal.*[44]

238. On this basis, we believe sufficient evidence was provided to demonstrate to the ERA that the costs associated with the completion of the BTP will allow Western Power to deliver significant ongoing savings for customers over the AA4 period and beyond, and therefore meet the requirements of section 6.40 of the Access Code.

239. Whether these cost savings are specific or not is not relevant. The test is whether the overall opex allowance would be incurred by a service provider efficiently minimising costs. We contest that costs of $28 million are far outweighed by an in-period savings of $158 million in both opex and indirect costs and the ongoing benefit of these cost reductions to our customers over future access arrangement periods.

240. Should the ERA maintain its view that the $28 million of costs associated with the completion of the BTP be removed in its final decision, Western Power would be unable to deliver the $158 million of efficiencies forecast in AA4, and would need to reverse the associated contingent adjustments, including the $5 million recurrent opex step change.

4.2.2 ERA required additional step change – Metering opex

241. In its review of metering capex, GHD considers Western Power overestimated the number of replacement non-compliant meters and therefore recommended the ERA reduces our forecast opex by $2.2 million per annum stating *for the adjusted reduced volumes of meters we have accepted for AA4…the annual opex allowance has been adjusted by $2.2 million per annum.*[45]

242. The AA4 proposal was based on Western Power installing 355,493 new and replacement meters. In its draft decision the ERA adjusts the forecast number of meter replacement to 273,493 to be consistent with the number of new meters included in the demand forecast and a reasonable forecast of non-compliant meters

43 Paragraph 206, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
44 Page 190, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.
45 Page 212, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

requiring replacement. However, as described in footnote 50 of the draft decision, subsequent advice from GHD led the ERA to amend its forecast metering volumes to 331,925. The difference in assumptions related to metering capex for replacement non-compliant meters is discussed in section 6.3.3.2.

243. In addition, Western Power notes in a separate section of the GHD report regarding Western Power's Advanced Metering Infrastructure (AMI) program GHD states *the additional $2.2 million per annum allowed for maintenance of the communication infrastructure has also been removed.*[46]

244. Western Power is therefore unsure of the basis on which the additional step-change has been determined.

245. Western Power confirms that the efficient base year does not include any opex for maintenance of the AMI communication infrastructure nor did we propose a step-change upwards to reflect the proposed expenditure. In addition, with respect to metering volumes, Western Power understands that the ERA had insufficient time to include the amended capex forecast in the draft decision, instead noting that this adjustment would be made in its final decision. Consistent with this decision, we expect that the ERA also intends to reverse its associated opex step change.

246. We further note that this type of bottom-up reduction for specific activities is inconsistent with our forecasting method. ACIL Allen provides the following opinion:

> *If the ERA singles out operating and maintenance expenditure in one cost category that may decrease during the access arrangement period, then it should also single out operating and maintenance expenditure in other cost categories that will increase during the period. This becomes a bottom up approach, which is inconsistent with the revealed cost approach that the ERA has adopted.*[47]

247. For this reason we have not accepted the ERA's proposed step-change reduction of $2.2 million.

4.3 Network growth escalation

248. As the prevailing best-practice method at the time, for the AA4 proposal Western Power used the 2014 Economic Insights approach to escalate our base year opex separately for the transmission[48] and distribution[49] businesses. The Economic Insights approach is designed to accurately reflect changes in the size of the network so that escalation can be factored into a network business' forecast opex. This approach is routinely adopted by the AER.

249. In its draft decision, the ERA removes network growth escalation in its entirety on the basis that it is inconsistent with the costs that would be incurred by a service provider efficiently minimising costs.

250. However, it appears that the ERA is not averse to Western Power using the Economic Insights approach to escalation. The ERA notes that:

> *If the AER network growth escalation method is to be used, it should reflect the most recent data from the AER, including the current weightings used by the AER.*[50]

251. The most current weightings are those in the 2017 Economic Insights reports.[51]

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[46] Page 122, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018

[47] Page 12, *Operating Expenditure Expert Report*, ACIL Allen, June 2018.

[48] Page 9, Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and Tasmanian Electricity TNSPs*, 10 November 2014.

[49] Page 7-49, *SA Power Networks determination 2015-16 to 2019-20, Final Decision, Attachment 7 – Operating expenditure*, AER, October 2015.

[50] Paragraph 191, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[51] *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017 and *Position Paper for Review of TNSP Economic Benchmarking*, 9 August 2017.

252. Specifically, in addition to applying the 2017 Economic Insights weightings, the ERA requires Western Power to:

- not apply network growth escalation to corporate opex forecasts
- update circuit length forecasts for the AA4 period
- update transmission energy volumes to include energy delivered to distribution customers
- provide evidence to support the $75 per new customer cost increase that results from scale escalation.

253. We maintain that the AER's network growth escalation method, which is based on the Economic Insights approach, is the most effective way of applying estimation and results in a forecast of operating costs consistent with that which would be incurred by a service provider efficiently minimising costs

254. We have therefore followed the ERA's advice to update the escalation approach to reflect the most recent data from the AER, applying the entire forecasting method from the Economic Insights 2017 reports. Consequently, we have made amendments to our proposed opex forecast.

255. Each of the ERA's amendments to the opex forecast, and our amendments to reflect the 2017 Economic Insights reports are discussed in the following sections.

4.3.1 Application of network growth escalation to corporate opex

256. The ERA states that network growth escalation should not be applied to corporate opex:

> *The ERA considers business support activities such as information technology, levies, fees and insurance are not proportional to any growth in service outputs that may result from changes in customer demand. Consequently, no growth escalation should be applied to corporate costs.*[52]

257. Economic Insights' model specification is based on the network service provider's total operating and maintenance expenditure, including corporate-related operating expenditure. The model does not contemplate that corporate costs be excluded from network growth escalation.

258. ACIL Allen notes that:

> *[The ERA's application] is not consistent with the appropriate application of this model specification. The Economic Insights' model specification needs to be applied to Western Power's total operating and maintenance expenditure, or a different model specification is required.*[53]

259. We consider the application of Economic Insights' method in its entirety, including corporate opex and expensed indirect costs, as proposed in our revised proposed forecast opex is necessary to deliver an opex allowance consistent with section 6.40 of the Access Code.

4.3.2 Circuit length forecasts

260. In the AA4 proposal, we determined values for the circuit length based on the historical average growth rate rather than forecast AA4 growth. This is because:

- most of our increase in circuit length will be driven by customer driven projects. Customer driven works are highly volatile and whether they proceed (or not) is outside Western Power's control. This

[52] Paragraph 191, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
[53] Page 12, *Operating Expenditure Expert Report*, ACIL Allen, June 2018.

makes them difficult to forecast with any reasonable degree of accuracy. We therefore forecast customer driven works based on historical averages

- the ERA required Western Power to use the historical growth rate (rather than a circuit length forecast) in its AA3 determination.[54]

261. In addition, in its review of Western Power's proposed network growth forecast rated to circuit length, GHD noted:

> *…Western Power has based its circuit length growth on historic AA3 distribution network growth, due to forecasting accuracy difficulties. We accept that these difficulties are valid, as the review of AA3 CAPEX has noted that actual AA3 distribution growth CAPEX was 28% less than the approved allocation due to a depressed state economy, and renewable generation and energy efficiency initiatives being adopted by customers in lieu of previously planned network augmentations. Therefore, we accept using actual AA3 changes in network length as a proxy for changes in AA4, as we anticipate there will be similar underspend in growth CAPEX due to changing customer requirements and associated project deferrals.*[55]

262. There is risk associated with any forecast. In one regulatory period, it is likely that the forecast will result in higher than historical average rates, and in others it will result in lower than historical actual average growth rates. However, these outcomes will balance out over time and should not drive changes to the forecasting method.

263. We have therefore not updated our distribution or transmission circuit length network growth factors.

Table 4.2: Circuit length network growth factor

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission circuit length	7,781	7,805	7,831	7,849	7,874	7,900
Annual growth rate		0.32%	0.33%	0.22%	0.33%	0.32%
Distribution circuit length	94,200	95,060	95,928	96,804	97,688	98,580
Annual growth rate		0.91%	0.91%	0.91%	0.91%	0.91%

4.3.3 Transmission energy volumes to include energy delivered to distribution customers

264. As required by the ERA, and consistent with the Economic Insights 2017 reports, we have updated the transmission energy volumes to account for volumes delivered to both transmission and distribution customers. The proposed and the revised proposed growth rates are provided in Table 4.3.

Table 4.3: Energy delivered network growth factor

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Proposed energy delivered	3,995	4,007	4,007	4,123	4,226	4,226
Annual growth rate		0.30%	0.00%	2.89%	2.50%	0.00%
Revised proposed energy delivered	17,764	17,698	17,663	17,628	17,502	17,309
Annual growth rate		-0.37%	-0.20%	-0.20%	-0.71%	-1.10%

[54] Paragraph 257, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, March 2012.

[55] Page 186, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

4.3.4 $75 per new customer is efficient

265. The ERA states that it is:

> *…not convinced the distribution cost escalation attributed to an increase in customer numbers is accurate and consistent with a service provider efficiently minimising its costs. The proposed scale escalation results in $75.00 of recurring operating expenditure being added for each new customer. The ERA would need to see evidence to support this cost increase before approving any customer growth scale escalation.*[56]

266. ACIL Allen provides an opinion on the ERA's use of an outworking of the application of an econometric cost model, which, in its opinion *"needs to be accepted or rejected in its entirety….the econometric cost model cannot be applied in part in the way that the ERA is seeking to do."*[57]ACIL Allen further notes:

> *There are legitimate additional costs that are incurred for each new customer. The most significant of these costs are the costs associated with metering. For each new customer, there is an additional meter that needs to be installed and read. The costs will vary from customer to customer based on the location of that customer and the type of meter installed but is generally in the order of $50 per annum. Additionally there will be costs associated with the call centre, customer service etc.*
>
> *The ERA has identified that comparable networks to Western Power are SA Power Networks and ElectraNet. The equivalent cost per customer for SA Power Networks is around $185 per customer. One of the reasons that the cost per customer for SA Power Networks is higher than for Western Power is because the weighting on customer numbers is higher for SA Power Networks (67.6 per cent) than for Western Power (45.8 per cent).*
>
> *For these reasons, it is my opinion that the ERA cannot conclude that a service provider efficiently minimising costs would not incur costs of $75 per new customer.*[58]

4.3.5 Additional amendments to reflect 2017 Economic Insights escalation method

267. As advised by the ERA, we have adopted the updated weightings for scale escalation factors provided in the 2017 Economic Insights reports. We have also adopted a number of other changes to reflect the full Economic Insights method. These amendments are discussed in the following section.

4.3.5.1 Application of energy delivered metric to distribution

268. In its 2017 review, Economic Insights added a new metric to its distribution network growth factors to reflect the volume of energy delivered.

269. In its draft decision, the ERA appears to have applied the most recent weightings for distribution network service providers, but has combined two of the measures – ratcheted maximum demand and energy throughput. As noted by the AER, the *substitution of one output growth factor with another would not be consistent with the weights used in forming the overall output growth derived in the econometric model.*[59]

270. ACIL Allen has provided the expert opinion that: *if the Economic Insights' econometric cost model is to be used to forecast growth, the measures and weightings need to be consistent with that model. That is, the*

56 Paragraph 195, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

57 Page 13, *Operating Expenditure Expert Report*, ACIL Allen, June 2018.

58 Page 13, *Operating Expenditure Expert Report*, ACIL Allen, June 2018. (Footnotes have not been included in quoted text)

59 Pages 7-50 and 7-51, *Final Decision, SA Power Networks determination 2015-2020, Final Decision, Attachment 7 – Operating expenditure*, AER, October 2015.

weightings for the two measures – ratcheted maximum demand and energy throughput – should not be combined.[60]

271. On this basis, we have applied the Economic Insights method and retained the two separate measures:

- ratcheted maximum demand
- energy throughput.

272. We have therefore added the energy delivered metric to our demand network growth metrics, and used the same values as used for transmission network growth factors for our distribution energy throughput growth factor. As required by the ERA, and consistent with the Economic Insights 2017 reports, we have updated the transmission energy volumes to account for volumes delivered to both transmission and distribution customers. The proposed and the revised proposed growth rates are provided in Table 4.3 above.

4.3.5.2 Definition of transmission customer metric

273. In its 2017 review, Economic Insights made a number of changes to its method. To apply the new method in its entirety, as it was developed for implementation, we have also updated the transmission customer metric definition.

274. In the 2014 method, Economic Insights defined the transmission customer metric as the voltage weighted connections. However, following significant consultation, in 2017 Economic Insights replaced this with the number of end-users[61]. We have therefore updated our transmission customer connection metric definition accordingly. The proposed and the revised proposed growth rates are provided in Table 4.4.

Table 4.4: Transmission customer network growth factor

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Weighted entry and exit conn. point	27,137	27,071	26,873	26,807	26,543	26,543
Annual growth rate		-0.24%	-0.73%	-0.25%	-0.98%	0.00%
Transmission customers	38	38	38	39	40	40
Annual growth rate		0.00%	0.00%	2.63%	2.56%	0.00%

4.3.5.3 Network growth metric weightings

275. We have updated our network growth weightings consistent with the definitions and weightings in the 2017 Economic Insights reports. The revised proposed network growth weightings and resulting growth factors for our transmission and distribution opex forecasts are provided in the following tables.

Table 4.5: Transmission network growth factors, per cent per annum

	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Circuit length	37.6	0.32	0.33	0.22	0.33	0.32	
Ratcheted max. demand	19.4	0.00	0.00	0.00	0.00	0.00	
Energy delivered	23.1	-0.37	-0.20	-0.20	-0.71	-1.10	

60 Page 13, *Operating Expenditure Expert Report*, ACIL Allen, June 2018.

61 See Page 2 of the Economic Insights 2017 TNSP report for more information on this change.

	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Transmission customers	19.9	0.00	0.00	2.63	2.56	0.00	
Transmission network growth	**100.0**	**0.03**	**0.08**	**0.56**	**0.47**	**-0.13**	**0.20**

Table 4.6: Distribution network growth factors, per cent per annum

	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Customers	45.8	1.65	1.73	1.69	1.66	1.63	
Circuit length	23.8	0.91	0.91	0.91	0.91	0.91	
Ratcheted max. demand	17.6	0.00	0.00	0.00	0.00	0.00	
Energy delivered	12.8	-0.37	-0.20	-0.20	-0.71	-1.10	
Distribution network growth	**100.0**	**0.92**	**0.98**	**0.97**	**0.89**	**0.82**	**0.92**

276. We have applied these network growth factors to our base year with recurrent step changes as shown in our opex model provided with this submission.

4.4 Efficiency dividend

4.4.1 Amount of efficiency dividend

277. In developing our AA4 opex forecasts, we included an efficiency factor of one per cent compounding over the period. We have retained this efficiency factor in our revised proposed opex forecast.

278. ACIL Allen commented on our efficiency dividend:

> *Western Power proposed a 1 per cent per annum productivity improvement, in addition to the negative step change of $5 million and the productivity that is incorporated in Economic Insights' econometric cost function. While this is an appropriate application of the 'base-step-trend' approach, it is more than the expected productivity improvements for other network service providers. The AER's most recent (draft) decision for a transmission network service provider included forecast productivity growth of 0.2 per cent per annum and the AER's recent decision for the Victorian distribution network service providers provided for no productivity growth.*[62]

279. In its draft decision, the ERA ***assumed*** *the one per cent annual reduction is consistent with what would be achieved by a service provider efficiently minimising costs.*[63] *[emphasis added]*

280. In making this statement, the ERA has failed to make a clear decision on whether the efficiency dividend sufficiently accounts for the efficiencies expected of two specific programs:

1. depot modernisation
2. business driven IT systems.

[62] Page 9, *Operating Expenditure Expert Report*, ACIL Allen, June 2018. Footnotes have not been included in quoted text.
[63] Paragraph 201, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

281. ACIL Allen is of the opinion that:

> *if the ERA seeks to identify further productivity improvements, then it should also seek to identify whether there are any reasons why productivity may decrease over the AA4 period. This would require a full bottom up approach, rather than a selective top down approach.*[64]

282. As previously mentioned, our forecast opex has been developed using a top-down method, rather than bottom-up. Therefore, should the ERA continue to make such bottom-up assessment of specific programs of work, identifying only those with positive efficiencies, we would need to revert to a bottom-up opex forecast to equally identify those with negative efficiencies. The ERA would then need to assess those forecasts by individual line item forecasts and make an assessment of each.

283. This would not be ideal, as it would require us to re-forecast our opex and the ERA re-assess our forecast. The AER notes that *[t]he disadvantage of the bottom-up approach is that it is more susceptible to forecasting risk given the business has an incentive to inflate its forecasts.*[65] For these reasons, we consider the ERA's required amendment would result in an opex forecast that is inconsistent with section 6.40 of the Access Code and the Code objective.

284. Nevertheless, we reiterate that the efficiencies factored into our forecasts include capex efficiencies, opex efficiencies and indirect cost efficiencies totalling $158 million over the AA4 period. This more than compensates for the benefits associated with two additional programs, from which we do not expect to see benefits fully realised until after the completion of the full programs of work, in the AA5 period.

285. Importantly, as discussed in section 4.2.1, should the ERA require Western Power to remove the $28 million of costs associated with the completion of the BTP, we would be unable to deliver the $158 million of efficiencies forecast in AA4, and would need to reverse the associated contingent adjustments, including the one per cent efficiency dividend in whole or in part.

4.5 Non-recurrent network costs

4.5.1 Electricity Market Review

286. The AA4 proposal included $5.1 million of forecast opex associated with the transfer of the system operations function to the Australian Energy Market Operator (AEMO) as part of the State Government's Electricity Market Review (EMR) Phase 2 announced in March 2015.

287. The ERA removes these costs as:

> *AEMO's allowable revenue (the costs it is permitted to charge WEM participants) included provision for the costs of transferring system management functions from Western Power to AEMO. It is unclear why Western Power is seeking funding through the access arrangement process for system management costs. Any such costs should be (and presumably were) recovered through the contract it had with AEMO.*
>
> *In any case, the ERA considers system management costs do not form part of the provision of network covered services and therefore should not be included in Western Power's AA4 forecast operating expenditure.*[66]

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64 Page 14, *Operating Expenditure Expert Report*, ACIL Allen, 27 May 2018.

65 Page 7-8, Draft Decision Attachment 7 Operating expenditure AusNet Services 2018-22, AER, July 2017.

66 Paragraph 211, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

288. The ERA appears to have incorrectly assumed that:

- Western Power would not have incurred costs associated with the segregation of its network operations functions, processes and systems from those of System Management
- the transfer of System Management was the only EMR activity included in the forecast AA4 opex.

289. We incurred $14 million of costs associated with the separation and transfer of the system management function from network operations. The majority of this cost (circa 80 per cent) has been charged to the AEMO under our service level agreement and recovered from wholesale market participants. The remaining costs were required to enable the network operation function to operate independently as part of the covered network. These costs include:

- establishing and negotiating service agreements and operating protocols with the AEMO
- changes to ICT systems and processes to remove network operations elements from the following System Management systems:
  - Market Outage Management System
  - Operational Datastore
  - System Management Market IT Systems,

  and move them to the network operations Electronic Network Access Request system
- Western Power's portion of the communications link between its SCADA systems and the AEMO's new eTerra system.

290. Western Power will continue to incur costs associated with the transition over the AA4 period primarily for the remediation of ICT systems to finalise the disaggregation, including:

- reviewing and revising network operations processes and systems to allow continued operation following the AEMO's upgrades to, or replacement of System Management systems
- commercial and legal works to renegotiate the necessary replacement contractual agreements following the conclusion of the services agreement in October 2018.

291. Western Power and the AEMO have agreed the apportionment of costs to each party, and formally documented these in a services agreement. Under the services agreement, Western Power and the AEMO made an assessment of the total costs and the proportion that should be recovered from wholesale market participants and Western Power's customers.

292. When reviewing our non-recurrent EMR costs we found that we had not removed the costs associated with internal staff for AA3. This was used in the base year opex and non-recurrent opex amount. We have therefore reduced the EMR non-recurrent opex amount by $1.1 million as shown in Table 4.7.

Table 4.7: Revised EMR non-recurrent opex ($ million real, June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
AA4 proposed forecast	3.7	1.2	0.2	-	-	5.1
Adjustment	-1.1					-1.1
Proposed revised forecast	**2.6**	**1.2**	**0.2**			**4.0**

293. We highlight that this forecast does not include costs associated with the State Government's implementation of a constrained network access regime announced in August 2017[67], or other electricity sector reforms that have been foreshadowed by the Government. The timing and scope of these reforms has not yet been determined to the extent that we are able to forecast our costs for these reforms over the AA4 period.

4.5.2 Business Transformation Program

294. In the AA4 proposal, we included non-recurrent costs of $28 million to complete the Business Transformation Program (BTP). In the proposal, we highlighted that the BTP:

- had significantly reduced our expenditure over the AA3 period, delivering $72 million of opex efficiencies (in addition to $207 million of capex and $51 million of indirect costs) for our customers, which have been reflected in our efficient base year
- was expected to deliver a further $17 million per annum of recurrent efficiencies associated with the completion of BTP initiatives already underway, totalling $85 million over the AA4 period[68]
- is expected to deliver further efficiencies that, although we cannot identify or calculate specific efficiencies, we have included a recurrent, compounding efficiency dividend totalling $73 million over the AA4 period.

295. In relation to the BTP, the program of work designed to deliver these efficiencies, the ERA states:

> *… it is not clear how any savings from the final element of the business transformation program during 2017/18 have been incorporated in Western Power's forecast operating expenditure.*
>
> *On that basis, the ERA considers the $28.3 million must be excluded as it is not consistent with a service provider efficiently minimising costs.*[69]

296. This was despite making the following explicit statements in AA4 proposal:

> *In accordance with the base-step-trend methodology, we expect, and therefore are offering reductions in our opex reflecting improvements in productivity.* ***We have applied a one per cent per annum negative adjustment.*** *This has reduced our opex forecasts by $48 million over the AA4 period, and wholly offsets the forecast network growth escalation.*
>
> ***This is based on Western Power's expectations of the additional cost savings we may be able to achieve, and is in addition to the included reduction in forecast opex of $512 million***[120] *over the AA4 period resulting from the:*
>
> - *reduced 2015/16 recurring opex savings of $12 million which in turn lowered our 2016/17 opex*
> - *reduced 2016/17 base year, which included further opex efficiencies of $60 million*
> - *forecast recurrent step change of $5 million from 2017/18.*
>
> *The forecast productivity gains are passed through to our customers as savings and reflect our commitment to manage our operating expenditure so that it remains flat over the AA4 period.*

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67 Public Utilities Office reforms - https://www.treasury.wa.gov.au/Public-Utilities-Office/Open-consultations-reviews/Constrained-Network-Access-Reform/.

68 This includes the step changes and resulting efficiencies associated with opex and indirect costs.

69 Paragraph 206, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[120] *Our opex forecast would have been $512 million higher than we have proposed over the five years of the AA4 period if the recurrent efficiencies to-date had not been realised. This does not include the expensed proportion of our total indirect costs, which would have been a further $82 million higher (see section 7.9).*

[emphasis added]

297. As previously mentioned, the efficiencies factored into our forecasts include capex efficiencies, opex efficiencies and indirect cost efficiencies totalling $158 million over the AA4 period and are directly linked to the completion of the BTP. We contest that costs of $28 million are far outweighed by an in-period savings of $158 million, not to mention the ongoing benefit of these cost reductions to our customers over future periods.

298. Should the ERA require us to remove the $28 million of costs associated with the completion of the BTP, we would be unable to deliver the $158 million of efficiencies forecast in AA4, and would need to reverse the associated contingent adjustments.

299. The efficiencies gained from the BTP as a complete program more than outweigh the $28 million cost of completion. We consider that a service provider efficiently minimising costs would complete this program given the potential benefits to customers.

300. This type of program is encouraged within the form of incentive regulation Western Power operates under. To reject the recovery of costs required to see the completion of a program that is proven to deliver efficiencies would undermine the incentive framework and dissuade the business from undertaking such programs in the future.

4.6 Labour cost escalation

4.6.1 Updated labour cost forecasts

301. The ERA requires Western Power to update its wage price forecasts to reflect current data.[70]

302. We engaged Synergies to update the labour costs forecasts to account for recent trends in the labour market. The updated Synergies report is provided at Attachment 4.1. A comparison of the proposed and revised proposed wage price forecasts is also provided in Table 4.8.

Table 4.8: Labour cost escalation, per cent per annum / CAGR

	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
October 2017 Real wage price growth	0.9	0.8	1.0	1.1	1.2	1.0
May 2018 Real wage price growth	0.4	1.3	1.6	1.6	1.6	1.3

4.6.2 Updated proportion of labour costs

303. In the AA4 proposal, we used the historical average labour cost component to calculate the proportion of labour costs in relation to total spend over the last two years. Using this method, we applied labour cost escalation to 40 per cent of total opex.

[70] Paragraph 233, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

304. In its recent decisions, the AER has determined that a benchmark efficient proportion of labour costs should be applied in preference to the actual labour cost component:

> *We consider that using a network business' actual input price weights would distort its incentive to use the most efficient mix of labour and non-labour inputs...*
>
> *It is important, in our revealed cost approach to forecast opex, that the past performance of a network business does not influence the rate of change used to trend forward the base year revealed opex.*
>
> *Forecasting the rate of change based on a network business' past performance, including its past input mix, would not provide a business an incentive to reveal its efficient costs.*
>
> *Using a business' revealed input mix provides a disincentive to use less of an input that is increasing more rapidly in price because it would reduce the forecast rate of change.*[71]

305. In its draft decision, the ERA requires Western Power to update the opex network growth escalation to reflect the 2017 updates made by Economic Insights. As part of this review, Economic Insights has also updated the proportion of labour costs[72] to:

- apply separate labour cost proportions for transmission and distribution network businesses
- decrease the distribution proportion from 62.6 per cent to 59.7 per cent[73]
- increase the transmission proportion from 62.6 per cent to 70.4 per cent[74].

306. We have applied these updated labour cost proportions to our opex forecasts for the AA4 period.

307. We have also calculated a revised labour cost proportion to apply corporate expenditure. This is based on a weighted average of the transmission and distribution labour cost proportions. The weighting between transmission and distribution is based on the proportion of transmission and distribution forecasts prior to application of cost escalation.

4.7 Revised proposed opex forecast

308. Table 4.9 shows a build-up of revised forecast opex by element. A comparison of the forecast to the draft decision is shown in Figure 4.2.

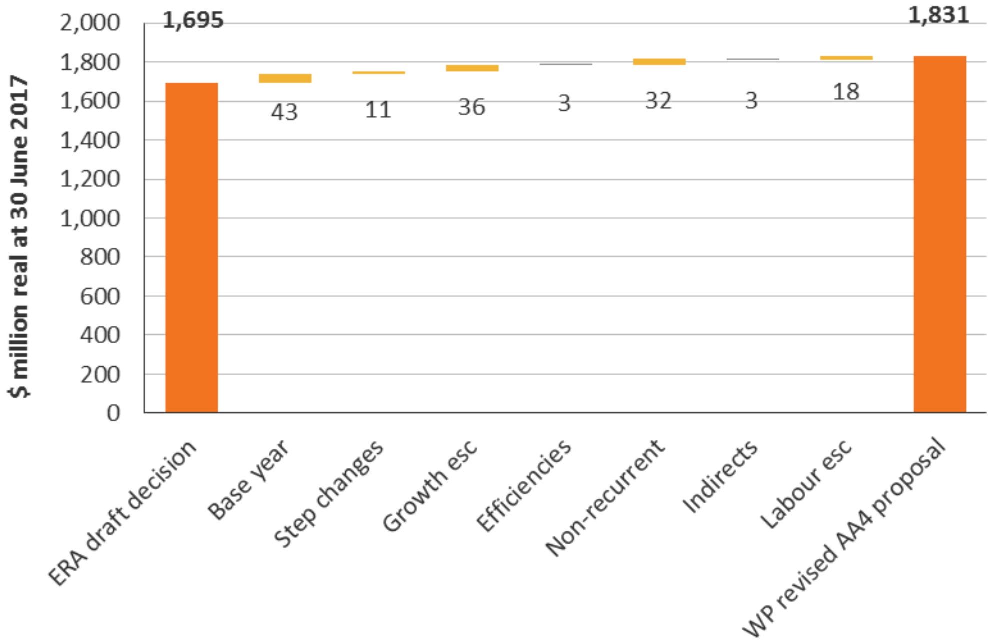
Table 4.9: Build-up of AA4 total opex forecasts ($ million real, 30 June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Efficient base year	320.0	320.0	320.0	320.0	320.0	320.0	1,600.0
Step changes		-5.0	-5.0	-5.0	-5.0	-5.0	-25.0
Total recurrent opex		315.0	315.0	315.0	315.0	315.0	1,575.0
Network growth escalation		2.2	4.7	7.4	10.0	11.9	36.3
Efficiency dividend		-3.2	-6.4	-9.6	-12.8	-16.0	-47.9
Non-recurrent opex		31.4	1.2	0.2	-	0.5	33.3

71 See for example page 7-14 of Attachment 7 – Operating Expenditure – ElectraNet transmission draft determination 2018-23.
72 This includes in–house labour, field services contracts and non–field services contracts.
73 Page 2, Economic Insights, *Economic Benchmarking Results for the AER's 2017 DNSP Benchmarking Report*, 31 October 2017.
74 Page 6, Economic Insights, *Economic Benchmarking Results for the AER's 2017 TNSP Benchmarking Report*, 6 November 2017.

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Expensed indirect costs		39.9	35.2	34.8	43.6	43.7	197.3
Labour cost escalation		0.9	3.6	7.0	10.7	14.3	36.5
Regulated revenue cap opex		**386.3**	**353.3**	**354.9**	**366.6**	**369.4**	**1,830.5**

Figure 4.2: Comparison of revised forecast operating expenditure ($ million real, June 2017) to the ERA draft decision



4.8 Indirect costs

309. In the AA4 proposal, we estimated we would spend $815 million on indirect costs. This included $189 million of expensed indirect costs, and $626 million of capitalised indirect costs. We developed our total indirect cost forecast using the same base-step-trend methodology as we used to forecast our opex.

310. In its draft decision, the ERA:

- accepts our base year indirect costs
- accepts our -$12 million step change related to BTP initiatives
- removes the -$10.5 million step change associated with the change in accounting treatment to capitalise fleet leases
- does not accept the application of network growth escalation to indirect costs
- accepts our one per cent efficiency dividend, but leaves the door open to apply a higher dividend.

311. The ERA therefore considers our proposed indirect cost forecast to be inconsistent with section 6.40 of the Access Code.[75]

312. Each of the ERA's required amendments are addressed in the following sections.

[75] Paragraph 220-224, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

4.8.1 Removal of negative step change for fleet capitalisation

313. In the AA4 proposal, we submitted that fleet leases should be capitalised and added to the regulated asset base. We therefore proposed a -$10.5 million recurrent step change in our indirect cost forecast and a related increase in capex.

314. The ERA considers Western Power should maintain the current arrangements for fleet, as unregulated assets, and fleet expenditure should not be capitalised. The ERA:

- removes fleet expenditure from the AA4 forecast capex
- removes our associated proposed negative step change of $10.5 million commencing in 2019/20.

315. We accept this amendment and have made the necessary changes to our expenditure forecasts.

4.8.2 Application of network growth escalation from indirect costs

316. As discussed in section 4.3.1, the ERA has applied the Economic Insights' econometric cost function to forecast growth in operating and maintenance expenditure. The model specification includes operating and maintenance expenditure inclusive of corporate costs and indirect costs that are expensed.

317. ACIL Allen provides the opinion that *[t]he Economic Insights' model specification needs to be applied to Western Power's total operating and maintenance expenditure, or a different model specification is required*.[76]

318. On this basis we have amended our forecast approach to first split our indirect cost forecast into expensed and capitalised indirect costs, and then apply network growth escalation to the expensed proportion of our indirect costs. The capitalised proportion of our indirect costs will be escalated in line with our forecast capex.

4.8.3 Application of a one per cent compounding efficiency dividend

319. In the AA4 proposal, we applied the one per cent compounding efficiency dividend to the total indirect cost forecast. This means our capitalised proportion of indirect costs were also reduced.

320. In its draft decision, the ERA stated that it *will further consider productivity improvements*[77] in relation to our indirect cost forecast. If the ERA seeks to identify further productivity improvements, then it should also seek to identify whether there are any reasons why productivity may decrease over the AA4 period.

321. We also note that although we have not applied network growth escalation to our capitalised proportion of our indirect costs, we have continued to apply the one per efficiency dividend to our total indirect cost forecast.

[76] Page 14, *Operating Expenditure Expert Report*, ACIL Allen, 27 May 2018.
[77] Paragraph 223, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

4.8.4 Resulting indirect cost forecasts

322. Table 4.10 shows a build-up of revised forecast indirect costs by element and Table 4.11 provides a break-down of the capitalised and expensed costs indirect cost forecasts.

Table 4.10: Build-up of AA4 total indirect cost forecasts, ($ million real, 30 June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Efficient base year	181.4	181.4	181.4	181.4	181.4	181.4	907.1
Step changes		-12.0	-12.0	-12.0	-12.0	-12.0	-60.0
Total recurrent opex		169.4	169.4	169.4	169.4	169.4	847.1
Network growth escalation		0.3	0.5	0.8	1.4	1.7	4.7
Efficiency dividend		-1.7	-3.4	-5.1	-6.7	-8.4	-25.3
Non-recurrent opex		-	-	-	-	-	-
Labour cost escalation		0.4	1.7	3.3	5.0	6.6	17.0
Regulated revenue cap opex		**168.4**	**168.3**	**168.5**	**169.0**	**169.3**	**843.5**

Table 4.11: Allocation of indirect costs, ($ million real, 30 June 2017, excluding labour cost escalation)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Capitalised indirect costs	128.1	131.4	130.4	120.4	119.0	629.2
Expensed indirect costs	39.9	35.2	34.8	43.6	43.7	197.3
Total indirect costs	**168.0**	**166.6**	**165.2**	**164.1**	**162.7**	**826.5**

5. Opening regulated asset base

323. This section details Western Power's response to the ERA's required amendments relating to the opening regulated asset base (RAB) for the AA4 period. This section covers:

- capital expenditure incurred during the AA3 period
- calculation of the AA4 opening RAB.

ERA required amendment 6:

The proposed access arrangement revisions must be amended to incorporate the forecast capital expenditure, depreciation and capital asset base values set out in this draft decision.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

324. The ERA's required amendment 6 is broad in that it covers changes to the opening and closing RAB for the AA4 period. While we agree with the RAB roll-forward method adopted by the ERA, our assessment of the capital expenditure amounts that satisfy the new facilities investment test (NFIT), as defined in section 6.52 of the Access Code, varies from the ERA's. As a result, we have not made the ERA's required amendments to the opening and forecast AA4 RAB exactly as required.

325. The following section discusses our alternative assessment of the AA4 **opening** RAB. Our assessment of the **forecast** AA4 RAB, including forecast depreciation and the forecast capital expenditure that satisfies the NFIT, is provided in chapter 6 of this document.

5.1 Assessment of the AA4 opening RAB

326. In order to determine the opening RAB for the AA4 period, Western Power must demonstrate the capital expenditure it undertook during the AA3 period satisfies the NFIT.

327. As the ERA describes in its AA4 draft decision; *the first part of the NFIT under section 6.52(a) of the Access Code is a test of whether the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, taking into account whether the new facility exhibits economies of scale or scope, the increments in which new capacity can be added and forecasts of sales of services.*[78]

328. The second part of the new facilities investment test under section 6.52(b) of the Access Code is *a test of whether the new facilities investment provides benefits that justify addition of the new facilities investment to the capital base of the covered network and the recovery of the cost of the investment from users of the network generally. The limbs of the second part of the new facilities investment test provide for new facilities investment to be added to the capital base if one or more of the following three conditions is satisfied:*

[78] Paragraph 282, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

- *Unless a modified test has been approved under section 6.53, the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment (the "incremental revenue test").*
- *The new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs (the "net benefits test").*
- *The new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services (the "safety and reliability test").*[79]

329. Expenditure that does not pass the NFIT cannot be added to the RAB and recovered through regulated network tariffs.

330. The ERA sought advice from its technical consultant, Geoff Brown and Associates (GBA) on whether Western Power's AA3 expenditure was consistent with the requirements of the NFIT. It is worth noting GBA also conducted ex-post reviews of Western Power's capital expenditure for the ERA during the AA2 and AA3 review processes, and as such has closely scrutinised Western Power's governance processes, investment decisions and asset management improvements over the past decade.

331. GBA conducted a thorough top-down and bottom-up review of Western Power's AA3 capital expenditure, and concluded the following:

> *Over the course of AA3, Western Power has significantly improved the efficiency of its management of capital expenditure (capex). These improvements relate both to the selection of capex projects and to the use of capital once projects have been committed for implementation. Total capex over AA3 was 22% lower than the approved expenditure forecast at the start of the regulatory period, and despite this, Western Power has still been able to meet or exceed the service levels that it promised its stakeholders. While some capex reductions were due to forecast demand growth not materialising, we think that improved project identification and expenditure management were significant factors in delivering this result.*[80]

332. GBA did, however, identify some expenditure it considered did not fully meet NFIT requirements. These were:

- future decommissioning costs for various substations ($7.16 million);
- provision for future removal of asbestos ($2.6 million);
- undergrounding the Manning-Osborne Park 132 kV transmission line ($2.13 million)
- capitalisation of intellectual property related to work undertaken in preparation for the transition to the national regime ($6.7 million).

333. GBA also identified that Western Power advised that (in Western Power's view) $1.78 million of capital expenditure relating to the Perenjori battery storage system did not satisfy the NFIT. However, GBA reviewed the Perenjori business case and *considers the expenditure to be reasonable and to fully meet NFIT requirement*[81]*,* and therefore recommended it be included in the AA4 opening RAB.

334. GBA's recommended reductions in new facilities investment to be added to the AA4 opening capital base are presented in Table 5.1

79 Paragraph 282, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
80 Page 1, *NFIT Review of Western Power's Capital Expenditure during the AA3 Regulatory Period, Geoff Brown & Associates*, April 2018.
81 Page 2, ibid.

Table 5.1: Summary of GBA's recommended AA3 capital expenditure ex-post review reductions ($ million real, June 2017)

Project	Amount that does not satisfy the NFIT
Future decommissioning costs for various substations	7.2
Asbestos removal provision	2.6
Manning-Osborne Park 132 kV line	2.1
Capitalisation of intellectual property for work completed in preparation for a transition to the national regime	6.7
Total	**18.6**

335. The ERA has broadly accepted GBA's recommendations, however, it has identified the following additional expenditure items that it considers do not meet NFIT requirements:

- $0.7 million for a transmission capital contribution for the medical centre substation
- $28.9 million for wood poles which it considers should have been included in operating expenditure.

336. Contrary to GBA's recommendation, the ERA has also disallowed the $1.78 million of capital expenditure on the Perenjori battery storage system from the opening AA4 RAB.

337. A summary of the ERA's reductions in new facilities investment to be added to the AA4 opening capital base are presented in Table 5.2.

Table 5.2: Summary of the ERA's AA3 capital expenditure ex-post review reductions ($ million real, June 2017)

Project	Amount that does not satisfy the NFIT
Future decommissioning costs for various substations	7.1
Asbestos removal provision	2.1
Manning-Osborne Park 132 kV line	2.0
Capitalisation of intellectual property for work completed in preparation for a transition to the national regime	6.7
Medical centre substation capital contribution	0.7
Wood poles expenditure included in operating expenditure	28.9
Perenjori battery storage system	1.8
Total	**49.3**

338. Western Power has reviewed the amounts of new facilities investment to be added to the opening RAB, as well as the requirements of the NFIT, and accepts several of the ERA's adjustments.

339. We agree that several of the items raised by the ERA do not fully meet the NFIT and should not be added to the opening AA4 RAB. In particular, we accept the ERA's interpretation of Section 6.49 of the Access Code, that:

> *the RAB must not include forecast new facilities investment. As a provision is a forecast, the ERA considers the decommissioning provisions are not consistent with the requirements of section 6.49 of the Access Code. Consequently, this amount must be removed from the opening capital base for AA4.*

340. As a result, we agree that the asbestos removal provisions and future substation decommissioning costs should not be added to the AA4 opening RAB, and have removed them from our RAB calculation.

341. However, we note that in Table 37 of the ERA's draft decision, the ERA has mistakenly attributed the substation decommissioning costs to Western Power's distribution RAB, rather than the transmission RAB. As substation decommissioning is a transmission activity, the amendment should be made to the transmission RAB instead.

342. Further, in light of the ERA's decision on provisions, we have identified additional decommissioning and asbestos removal costs, which we consider should not be added to the AA4 opening RAB.

343. The ERA's draft decision identifies the following substation decommissioning provisions for exclusion from the opening RAB (see Table 5.3).

Table 5.3: Decommissioning provisions identified by GBA ($ million real, June 2017)

Project No	Description	Amount that does not satisfy the NFIT
T0384182	Shenton Park Decomm Provision	1.0
T0384189	Herdsman Decomm Provision	1.5
T0389229	BP: Decommission Substation	1.2
T0433131	Durlacher Decomm Provisioning	3.5

344. We would like to highlight that the BP decommissioning project was not a provision, rather it was expenditure for a substation that was decommissioned during the period. Therefore while we have removed the provisions for Shenton Park, Herdsman and Durlacher from the AA4 opening RAB, BP should remain.

345. In addition to removing the provisions for Shenton Park, Herdsman and Durlacher we have identified and updated the decommissioning provisions to ensure actual AA3 closing 2016/17 provision are excluded from the opening RAB (see Table 5.4)

Table 5.4: AA3 actual closing 2016/17 provisions identified by Western Power ($ million real, June 2017)

Project No	Description	Amount that does not satisfy the NFIT
T0384182	Shenton Park Decomm Provision	1.0
T0384189	Herdsman Decomm Provision	1.4
T0433131	Durlacher Decomm Provisioning	4.2
Total		**6.5**

346. We have also identified additional decommissioning provisions that should be removed from the RAB (see Table 5.5).

Table 5.5: Additional decommissioning provisions identified by Western Power, ($ million real, June 2017)

Project No	Description	Amount that does not satisfy the NFIT
T0383976	University	1.9
T0378375	Medical Centre	0.7
T0448917	West Kalgoorlie	3.8
T0370855 & T0370856	Binningup	0.06
n/a	Eneabba-Three Springs and Three Springs to Karara Turnoff point	0.15
Total		**6.5**

347. We therefore submit that a total of $13 million for decommissioning provisions should be excluded from the AA4 opening RAB.

348. With regard to asbestos removal provisions, we have identified that the closing 2016/17 provisions amount was $2.6 million rather than the $2.1 million identified by the ERA. We have removed this amount from the AA4 opening RAB calculation accordingly.

349. We also accept the ERA's view that the intellectual property associated with the transition to the national regime should not be added to the AA4 opening RAB.

350. With regard to the Manning-Osborne Park 132 kV line and the Perenjori battery storage system, following inquiries from the ERA and its technical consultant regarding these projects, we advised the ERA that Western Power's own assessment was that the capital expenditure in question does not meet the NFIT and these amounts were inadvertently included in the RAB in the initial proposal. Therefore we have removed the $3.8 million associated with these two projects from the opening RAB as directed.

351. Table 5.6 summarises our position on each of the new facilities investment items identified by the ERA as not meeting NFIT requirements.

Table 5.6: Summary of Western Power's response to the ERA's draft decision on new facilities investment to be excluded to the AA4 opening RAB

Project	Amount ERA considers does not satisfy the NFIT ($ million real 2017)	Western Power's response to the ERA's draft decision
Future decommissioning costs for various substations	7.1	Excluded $13 million from AA4 opening RAB
Asbestos removal provision	2.1	Excluded $2.6 million from AA4 opening RAB
Manning-Osborne Park 132 kV line	2.0	Excluded from AA4 opening RAB
Capitalisation of intellectual property for work completed in preparation for a transition to the national regime	6.7	Excluded from AA4 opening RAB

Project	Amount ERA considers does not satisfy the NFIT ($ million real 2017)	Western Power's response to the ERA's draft decision
Medical centre substation capital contribution	0.7	Was not included in the AA4 opening RAB and remains excluded from the revised RAB calculation
Wood poles expenditure included in operating expenditure	28.9	Included in AA4 opening RAB
Perenjori battery storage system	1.8	Excluded from AA4 opening RAB
Total	**49.3**	**20.4 (excluded from AA4 opening RAB)**

352. The two new facilities investment exclusions on which Western Power has a different view to the ERA are:

- medical centre substation capital contribution ($0.7 million)
- wood poles expenditure included in operating expenditure ($28.9 million)

353. These two items are discussed in the following sections.

5.1.1 Medical centre substation capital contribution

354. In its draft decision, the ERA correctly states Western Power advised that it received a $0.7 million customer capital contribution for this project. However, the ERA incorrectly assumes this capital contribution has been added to the AA4 opening RAB.

355. Capital contribution figures for 2012/13 (the year in which the medical centre capital contribution was received), when broken down to the project level, show that that the medical centre contribution was accounted for in that year and that the 2012/13 figures reconcile to the capital contribution figures in the revenue model provided to the ERA.[82] The revenue model inputs total gross capital expenditure at the regulatory category level, and then deducts capital contributions received by regulatory category. This annual process ensures capital contribution are not added to the RAB.

356. Therefore we have not made the required amendment to the AA4 opening transmission RAB, as the $0.7 million capital contribution was appropriately excluded in our original RAB calculation.

5.1.2 Wood pole expenditure included in operating expenditure

357. In its draft decision, the ERA considers that $28.9 million of expenditure relating to unplanned (or emergency) replacement of wood poles should be excluded from the capital base, as it believes these costs have previously been treated as operating expenditure and to include them as capital expenditure would be a double count.

358. The ERA's view is brought about as a result of a change in Western Power's accounting treatment in November 2013, whereby improvements in data quality meant asset disposals could be accurately captured and 100 per cent of the cost of unplanned wood pole replacement could be capitalised. Prior to November 2013, obtaining accurate and reliable information to perform asset disposals was not

[82] Note due to the confidential nature of customer capital contributions, the project level breakdown of 2012/13 capital contributions, has been provided directly to the ERA and it not suitable for publication on the ERA's website.

practicable, so Western Power only capitalised a portion of each job (40 per cent), with the remainder left as operating expenditure and no disposal recorded.

359. Because the accounting method changed mid-period, and is therefore different to the accounting method in place when making Western Powers' AA3 revenue determination, the ERA considers capitalising the full cost of unplanned wood pole replacements from November 2013 onwards and adding them to the AA4 opening distribution RAB, would be a double count. This is because the ERA assumes the 60 per cent of costs that would have been considered operating expenditure under the original accounting method, would have been accounted for when determining the opex component of AA3 target revenue. Sixty per cent of the unplanned replacement costs for 2014/15, 2015/16 and2016/17 is $28.9 million, therefore this is the amount the ERA considers should be excluded from the distribution RAB.

360. We appreciate the change in accounting treatment adds complexity to the unplanned pole replacement assessment, and understand why the ERA might consider there may be a double count. However, we can confirm that the 60 per cent of capitalisation costs post November 2013 were not accounted for in the AA3 revenue determination and have not already been recovered from customers. Adding these costs to the AA4 opening RAB would not result in a double count.

361. When determining its target revenue for the AA3 period, Western Power adopted a base-step-trend method[83] of forecasting opex. This method, which is well established among regulators and network businesses, uses the revealed efficient level of operating expenditure in typically the penultimate year of one access arrangement period as the starting point for forecasting an efficient level of operating expenditure for the following access arrangement period.

362. Importantly, the base-step-trend method is not based on a bottom-up build at an individual activity or at a project level basis. Rather, it is a high level view of efficient expenditure, with the onus being on determining reasons why the forward-looking opex would vary from the revealed efficient costs.

363. Key considerations such as step changes (where costs are reasonably certain to increase or decrease) and trends (such as labour escalation and productivity improvements) are factored into the assessment of forecast efficient costs, however, unknown or unforeseen changes in costs are not accommodated. Nor is it contemplated that they are.

364. The change in capitalisation treatment relating to wood poles was not foreseen when developing the AA3 forecast and nor was it possible to forecast the number of unplanned wood pole replacements required. Therefore the 60 per cent of capitalised costs relating to unplanned wood pole replacements would not have been incorporated in the base year calculation, nor was it foreseen as a step change or a trend.

365. Further, in approving Western Power's forecast AA3 operating costs, the ERA determined that Western Power's forecast opex at **a total expenditure level** was consistent with a service provider efficiently minimising costs. Unlike new facilities investment (capex), which is subject to a bottom-up build of spend by project, there is no contemplation of opex at a project level during the access arrangement review and no requirement to do so by the Access Code. Nor is there provision for ex-post adjustment. Therefore it is unreasonable and most likely not practicable to retrospectively adjust opex at the activity level.

366. We therefore maintain that the 60 per cent capitalisation costs ($28.9 million) was not treated as opex, no revenue has been recovered from customers to account for the costs, and the capital costs of unplanned/emergency pole replacement satisfies the NFIT and should be included in the AA4 opening RAB.

[83] Referred to in the AA3 proposal as the 'base year-roll-forward method'.

367. With regard to the broader wood pole replacement program during the AA3 period, the ERA's technical consultant (GBA), conducted a thorough review of Western Power's new facilities investment during the AA3 period, including wood poles.

368. Western Power submitted detailed NFIT summaries, which included (but not limited to) cost estimation, unit rates, variance analysis, investment drivers, options analysis, and an explanation of how wood pole investment during the AA3 period satisfies the requirements of the NFIT. We also provided information on design standards and procurement policies, improvements in wood pole management strategies, and how the wood pole investment complied with Western Power's governance framework, which GBA advises *has significantly improved over the course of AA3*.[84]

369. GBA reviewed this information and put forward its expert opinion that the wood pole replacement program satisfies the NFIT, was lower than the approved expenditure forecast and resulted in improved asset management strategies during the period. [85]

370. In its draft decision, the ERA accepts the advice of its technical consult and has determined that the AA3 wood pole investment (with the exception of $28.9 million of unplanned pole replacements described above) meets NFIT and can be included in the opening AA4 RAB. The ERA states:

> *The ERA's technical consultant's review of the program has not identified inefficiencies in the delivery of the program. Although the unit costs were higher than forecast, Western Power has been able to provide reasons for those differences.* [86]

371. We submit that, consistent with the advice of GBA, the wood pole replacement capex during the AA3 period satisfied the requirements of the NFIT and should be included in the AA4 opening RAB.

5.2 Revised calculation of the AA4 Opening RAB

372. In its draft decision, the ERA accepts Western Power's calculation of the opening asset value, depreciation and asset disposals in the AA4 opening RAB. We have therefore made no changes to these line items in our revised calculation of the transmission and distribution opening RABs for the AA4 period.

373. Consistent with our commentary in section 5.1 above, we have revised our calculation of the opening RAB to exclude the new facilities investment associated with:

- future decommissioning costs for various substations;
- asbestos removal provisions;
- the manning-Osborne Park 132 kV line;
- capitalisation of intellectual property for work completed in preparation for a transition to the national regime; and
- the Perenjori battery storage system.

374. For the reasons explained in section 5.1, we have not excluded new facilities investment associated with:

- the medical centre substation capital contribution; and
- wood poles expenditure included in operating expenditure.

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84 Page 1, *NFIT Review of Western Power's Capital Expenditure during the AA3 Regulatory Period, Geoff Brown & Associates*, April 2018.

85 It is worth noting that GBA also conducted the forward-looking technical analysis of the wood pole forecast expenditure during the ERA's AA3 review, and is therefore fully informed on what the expected costs, deliverable and benefits of the program were before the work was undertaken.

86 Paragraph 343, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, May 2018.

375. Table 5.7 and Table 5.8 present the revised calculation of the transmission and distribution opening RABs for the AA4 period.

Table 5.7: Revised regulated asset base as at 30 June 2017 for the transmission network ($ million real, June 2017)

Transmission RAB parameter	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening RAB	2,816.7	2,928.6	3,163.2	3,199.2	3,138.0	
New facilities investment	210.2	342.3	159.3	120.7	106.7	939.2
Asset disposals	-4.4	-4.2	-9.3	-60.6	-1.4	-80.1
Depreciation	-94.0	-103.4	-114.1	-121.3	-129.4	-562.2
Accelerated depreciation	0.0	0.0	0.0	0.0	0.0	0.0
Closing RAB	**2,928.6**	**3,163.2**	**3,199.2**	**3,138.0**	**3,113.8**	

Table 5.8: Revised regulated asset base as at 30 June 2017 for the distribution network ($ million real, June 2017)

Distribution RAB parameter	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening RAB	4,248.7	4,707.8	5,142.3	5,504.4	5,746.2	
New facilities investment	677.8	671.5	628.9	511.2	363.0	2,852.4
Asset disposals	-0.9	-0.3	-4.9	-2.8	-0.6	-9.6
Depreciation	-214.0	-236.2	-261.9	-266.5	-281.5	-1,260.1
Accelerated depreciation	-3.8	-0.5	0.0	0.0	0.0	-4.3
Closing RAB	**4,707.8**	**5,142.3**	**5,504.4**	**5,746.2**	**5,827.1**	

6. Forecast regulated asset base

376. This section details Western Power's response to the ERA's required amendments relating to the forecast regulated asset base for the AA4 period. This section covers:

- forecast capital expenditure
- forecast depreciation
- calculation of the AA4 forecast RAB.

6.1 Forecast capital expenditure

377. The AA4 proposal, submitted in October 2017, included $3,514 million[87] of capital expenditure to be included in the AA4 forecast RAB. This forecast investment is designed to:

- maintain the current levels of safety risk associated with the network
- maintain current levels of service standard performance for the distribution and transmission network (reliability of supply and security of supply), as well as call centre and streetlight performance
- meet forecast growth in the customer base and demand
- satisfy compliance requirements
- continue to improve the efficiency of operations.

378. The AA4 capex forecast was based on the 2016 demand and customer number forecasts, and comprised the following split across the transmission, distribution and corporate regulatory expenditure categories:

- Transmission network – $883 million (25 per cent of total capex)
- Distribution network – $2,062 million (59 per cent of total capex)
- Corporate – $569 million (16 per cent of total capex).

379. In the course of making its draft decision, the ERA commissioned an expert consultancy firm (GHD) to conduct a technical review of Western Power's AA4 capex proposal. GHD's review included an assessment of Western Power's governance processes, asset management strategies and forecasts.

380. GHD advised that:

> *Western Power's governance policies and processes and procedures provide a good basis for governance of investment decisions and project delivery, and that Western Power addresses the principles of good governance well. GHD also found that the application of the policies, processes and procedures was in accordance with the relevant standards and guidelines.*[88]

381. And:

> *Western Power has invested in various parts of the business to improve weaknesses identified during the AA3 governance review. These included poor data on asset condition and the lack of a quantitative risk assessment tool. Western Power has addressed both these issues. Investment in Western Power's asset management framework has led to strengthened asset condition data and Western Power has developed a network risk management tool.*[89]

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87 Excluding capital contributions.

88 Paragraph 374, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

89 Paragraph 375, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

GHD concluded that:

> *…the level of maturity and effective integration of asset management practices in the business significantly strengthened over the AA3 period and that Western Power would now be considered as having an industry-leading asset management system in place.*[90]

382. Based on GHD's advice and its own review of Western Power's capex forecast, in its draft decision the ERA concludes:

> *Based on an assessment of the information provided by Western Power and GHD, the ERA considers Western Power's governance processes and asset management strategies are generally adequate to ensure its capital expenditure forecasts can reasonably be expected to satisfy the new facilities investment test.*[91]

383. However, the ERA makes some adjustments to forecast capex as it has identified some areas of expenditure that it considers are not reasonably expected to satisfy the NFIT.

384. The ERA's reductions to amount of new facilities investment approved for inclusion in the AA4 forecast RAB are summarised in Table 6.1.

Table 6.1: ERA amendments to forecast capex included in the AA4 forecast RAB, including indirect costs and escalation ($ million real, June 2017)

Expenditure category	AA4 proposal	ERA draft decision	ERA reduction
Transmission network	883.0	586.6	(296.4)
Distribution network	2,062.4	2,009.8	(52.6)
Corporate	568.9	451.9	(117.0)
Total	**3,514.3**	**3,048.3**	**(466.0)**

385. Significant capex exclusions by the ERA include[92]:

- reducing transmission asset replacement ($114 million)
- removing the new CBD substation ($62.2 million)
- reducing investment in substation security ($59.7 million)
- disallowing fleet costs from the RAB ($77.2 million)
- removing investment in IT and communications systems to support advanced metering ($40.1 million)
- removing the customer relationship management system upgrade ($24 million).

386. The ERA also requests Western Power updates its growth-related capex forecasts to reflect the 2017 demand and customer number forecasts.

387. We have reviewed the ERA's draft decision in detail, and taken into consideration the recommendations by GHD. In several instances, notably the CBD substation (exclusion of which Western Power had already provided notice to the ERA) and fleet costs, we accept the ERA's amendment and consider these items should not be included in the AA4 forecast RAB.

90 Paragraph 377, ibid.
91 Paragraph 381, ibid.
92 Excluding labour cost escalation and indirect costs.

388. However, we have not accepted all the ERA's capex exclusions and have either proposed a modified amount of capex or have maintained our original position. Where we have varied from the ERA's draft decision, we have provided additional evidence to demonstrate that the forecast capex is reasonably expected to satisfy the requirements of the NFIT and can be included in the AA4 forecast RAB.

389. Capex items where we have provided further information to support their inclusion include:

- transmission asset replacement
- substation security
- advanced metering communications infrastructure
- IT expenditure (specifically CRM and AMI costs).

390. Where possible we have provided further information on the criticality, deliverability and efficiency of the proposed investment, including cost benefit and options analysis.

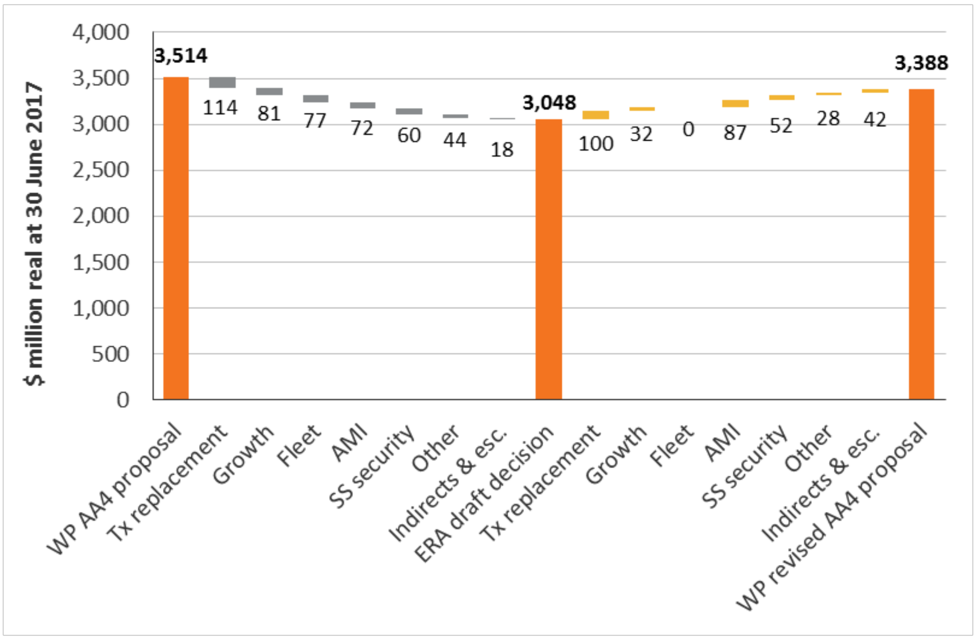
391. The revised AA4 capex proposal is summarised in Table 6.2.

Table 6.2: Revised AA4 capex forecast, including indirect costs and escalation ($ million real, June 2017)

Expenditure category	AA4 proposal	ERA draft decision	AA4 revised proposal
Transmission network	883.0	586.6	825.7
Distribution network	2,062.4	2,009.8	2,043.7
Corporate	568.9	451.9	519.0
Total	**3,514.3**	**3,048.3**	**3,388.4**

392. Figure 6.1 shows the changes in total forecast capex between the AA4 proposal, the ERA's draft decision, and the revised AA4 proposal.

Figure 6.1: Comparison of total capital expenditure, including indirect costs and escalation ($ million real, June 2017) excluding gifted assets and cash contributions



393. We submit that the revised AA4 capex proposal is reasonably expected to meet the requirements of the NFIT, and represents a prudent level of investment that will enable Western Power to:

- maintain the current levels of safety risk associated with the network
- maintain current levels of service standard performance for the distribution and transmission network (reliability of supply and security of supply), as well as call centre and streetlight performance
- meet forecast growth in the customer base and demand
- satisfy compliance requirements
- continue to improve the efficiency of operations.

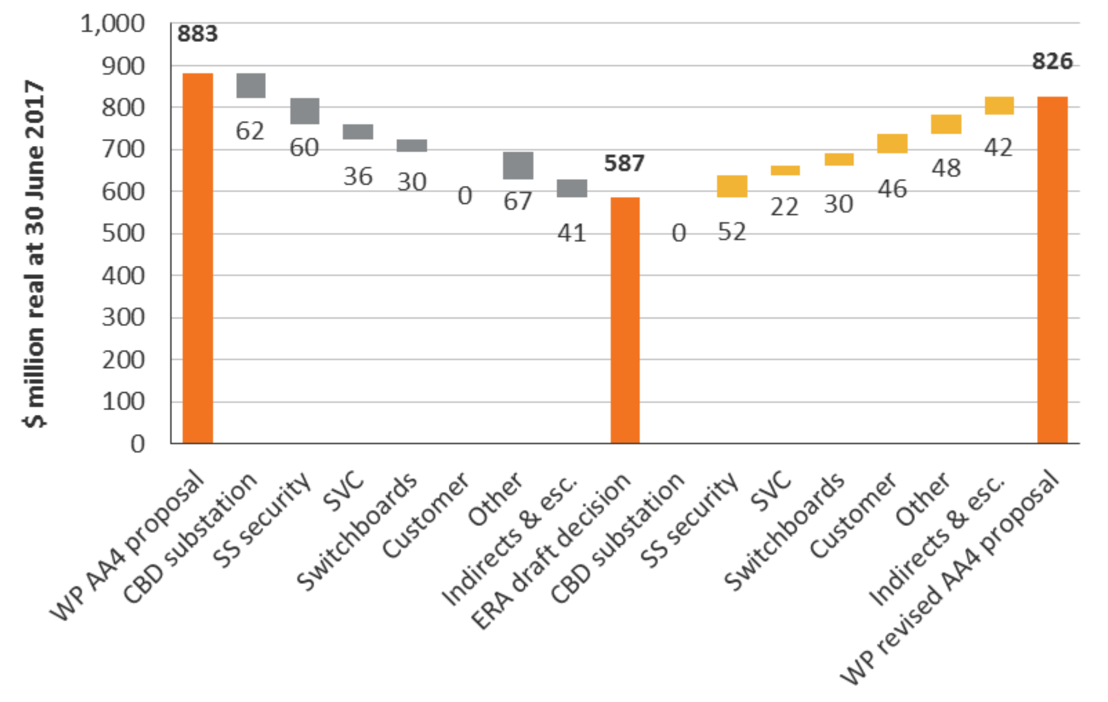
394. The ERA notes its:

> *…determination of forecast capital expenditure does not set limits on specific projects Western Power must undertake. During the access arrangement period, Western Power is free to manage its expenditures as it sees fit. The only requirement is that it must meet the new facilities investment test for the expenditure to be added to the capital base.*[93]

395. Actual capex incurred during AA4 may vary from the revised AA4 proposal as new information comes to hand or new regulatory obligations are placed on Western Power. Western Power's investment governance processes ensure that capex is appropriately prioritised and that all capex meets the NFIT.

396. The following waterfall charts show the variances between the AA4 proposal, the ERA's draft decision and the revised AA4 proposal for distribution, transmission and corporate expenditure.

Figure 6.2: Comparison of transmission capital expenditure, including indirect costs and escalation ($ million real, June 2017) excluding gifted assets and cash contributions



93 Paragraph 272, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Figure 6.3: **Comparison of distribution capital expenditure, including indirect costs and escalation ($ million real, June 2017) excluding gifted assets and cash contributions**

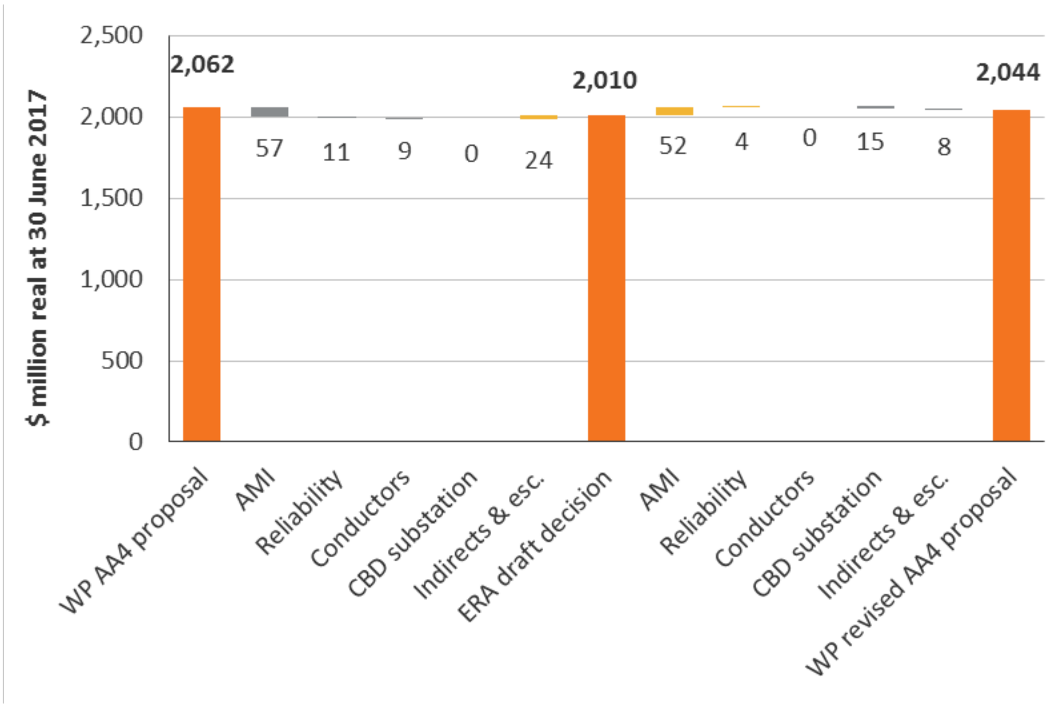
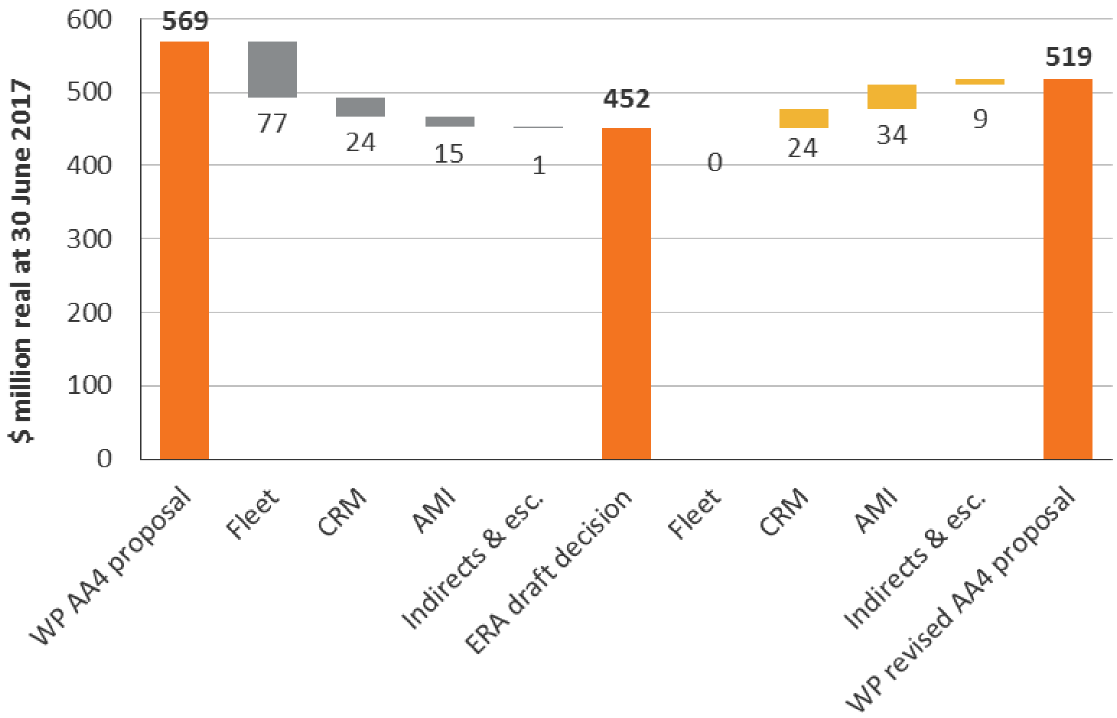


Figure 6.4: **Comparison of corporate capital expenditure, including indirect costs and escalation ($ million real, June 2017) excluding gifted assets and cash contributions**



397. The rationale and evidence to support our revised capex proposal is provided in the following sections.

398. To allow comparison with historical expenditure on a consistent basis, all amounts in sections 6.2, 6.3 and 6.4 are **presented as direct costs only, i.e. excluding indirect costs and labour cost escalation** unless otherwise stated.

6.2 Transmission capital expenditure

399. As discussed in the AA4 proposal, actual transmission capital expenditure during the AA3 period was lower than forecast in many categories. Due to some significant transmission network related issues, most notably the Muja bus-tie failures, a significant amount of transmission work during the AA3 period was reactive and some of the forecast transmission expenditure was deferred.

400. As a result, forecast transmission capital expenditure for the AA4 period is greater than that incurred during the AA3 period. However, this is more than offset by a decrease in forecast capex on the distribution network.

401. The forecast transmission investment for the AA4 period takes into account the 2017 growth forecasts and a forward-looking view of network usage and potential topology. The transmission investment approach focuses on achieving maximum risk reduction per dollar rather than adopting like-for-like replacements as the default options. For example, where possible and safe to do so, we will look to reduce transmission network footprint by decommissioning poor condition transformers and switchboards and retaining fewer assets in a reconfigured network.

402. Transmission network capex includes some 'one-off' lumpy investments such as static VAR compensators (SVCs), switchboards and protection systems, which are required to address known network safety and reliability risks associated with assets that are obsolete and/or underperforming.

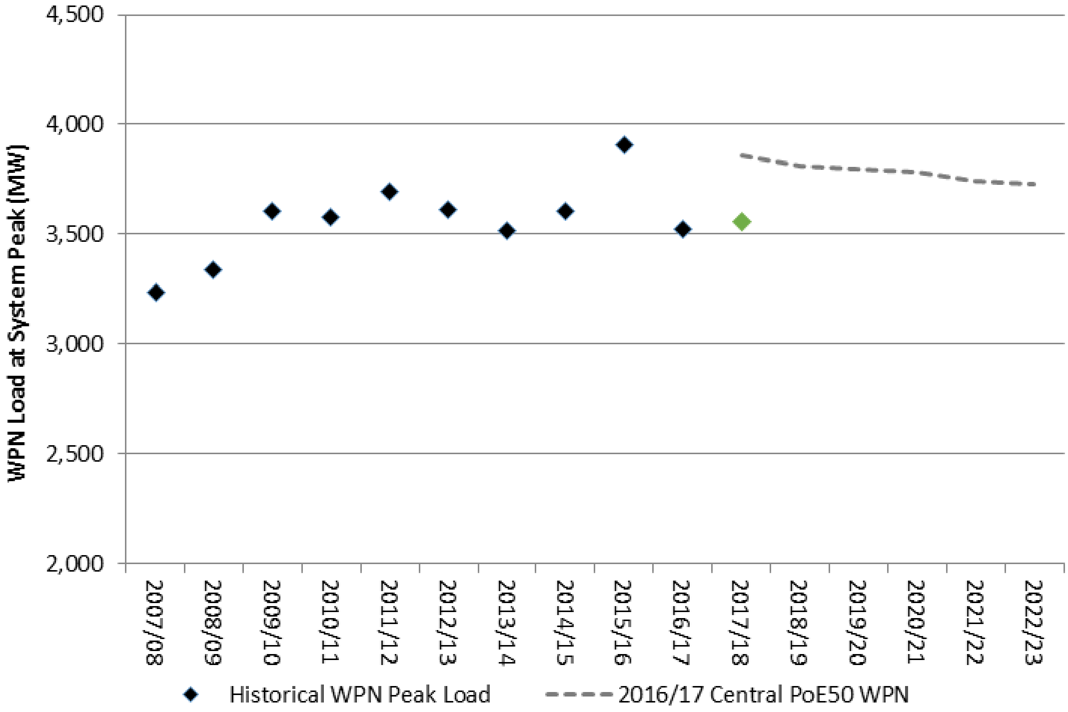
403. Our revised AA4 transmission capex proposal, including our response to the ERA's amendments, is discussed in the following sections.

6.2.1 Transmission growth

404. In the AA4 proposal, forecast growth capex was based on the 2016 demand and customer number forecasts. Though 2017 demand and customer number forecasts were provided to the ERA, there was insufficient time during the access arrangement revisions development process to factor the revised demand forecasts into the AA4 capex proposal.

405. We have since reviewed the AA4 capex transmission (and distribution) forecasts against the 2017 demand and customer numbers. The 2017 forecasts provided to the ERA have proven accurate across most measures. The 2017/18 annual peak was towards the lower end of the expected range as can be seen by the green marker in Figure 6.5. However, this can be explained by a milder than forecast summer.

Figure 6.5: Western Power Network load at system peak



406. The 2017 forecast results in limited changes to the overall growth expenditure forecast. The only program that has been deferred as a result is the proposed investment on a new CBD substation, which we had previously flagged with the ERA as being likely to be no longer required.

6.2.1.1 Transmission customer driven

407. There is a relatively low impact on transmission customer-driven work[94] for the AA4 period, which we forecast will increase from the $41 million[95] put forward in October 2017 to $67.9 million[96] in this revised AA4 proposal.

408. This $26.9 million increase is due to:

- the introduction of the Generator Interim Access (GIA) solution, which will facilitate the connection of eight new generators prior to the implementation of a constrained market (proposed October 2022 but not yet committed). Three access contracts have been executed to date totalling 330 MW of new generation
- large projects including the Warradarge and Yandin wind farms, and new load customers seeking network access in the Eastern Goldfields area
- major investment in lithium projects, for example the Tianqi Kwinana lithium processing plant (under construction) and associated Talison minesite expansion, and other proposed major projects including the Abermarle Kemerton Plant.
- forecast Government investment in infrastructure projects such as Metronet, which is likely to result in demand for relocation work.

94 It is worth noting the 2017 demand forecast results in no increase in distribution customer-driven forecast capex.
95 Excluding capital contributions ($94.3 million including contributions).
96 Excluding capital contributions ($150 million including contributions).

409. The growth expenditure category is included in the investment adjustment mechanism (IAM), which provides for revenue adjustments in the AA5 period to accommodate variances from forecast. However, we consider the customer driven initiatives listed above are sufficiently progressed and/or certain to materialise to justify them being included in the AA4 forecast RAB (net of capital contributions).

410. In the AA4 proposal we submitted we would consider the potential impact of the Muja AB, Western Kalgoorlie and Mungarra generator retirements, which were forecast to occur during 2018, and make any necessary amendments in our response to the ERA's draft decision.

411. The retirement of these generators has not progressed significantly beyond their status at the time of submitting the AA4 proposal (October 2017). In particular, information about the capacity, non-network, and/or energy services required following these retirements has not been clarified sufficiently to allow Western Power to submit a robust forecast in this AA4 proposal.

412. The Western Kalgoorlie and Mungarra generators are scheduled for retirement on 1 October 2018. At the time of preparing this submission, decisions regarding post-October 2018 requirements have not yet been confirmed by the various parties involved.

413. As a result, we have not revised our transmission growth capex forecasts to accommodate any new facilities investment required due to these generator retirements. When further clarity regarding the post-retirement requirements and costs is available, Western Power will issue a submission to the ERA under the D-factor provisions to enable the business to recover any efficient costs incurred.

6.2.1.2 Transmission capacity expansion

414. In its draft decision, the ERA excludes capex associated with the following transmission growth (capacity expansion) projects from the AA4 forecast RAB:

- CBD new substation ($62.2 million)
- Picton-Busselton 132 kV line ($19.2 million).

415. Actual growth expenditure during the AA3 period has generally been less than forecast, and has resulted in revenue adjustments for the AA4 period via the IAM. The ERA states its *final decision on growth expenditure for AA4 will only include expenditure for projects that are reasonably likely to proceed in the AA4 period to minimise the likelihood of under expenditure against forecasts.*[97]

416. Table 6.3 shows the ERA's forecast capex amendments to transmission growth projects (customer-driven and capacity expansion combined).

Table 6.3: Draft decision transmission growth capital expenditure ($ million real, June 2017)

Transmission growth capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Western Power AA4 proposal	33.6	34.2	46.8	67.5	58.8	240.8
CBD substation	(0.2)	(0.3)	(6.4)	(27.6)	(27.6)	(62.2)
Picton-Busselton 132 kV line	(0.5)	(0.5)	(15.6)	(2.2)	(0.3)	(19.2)
Draft decision	**32.8**	**33.4**	**24.8**	**37.6**	**30.8**	**159.4**

Source: Table 48, ERA draft decision

97 Paragraph 399, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

417. We have reviewed the ERA's reasoning for these amendments, along with the advice provided in the ERA's technical consultant's report (GHD's technical review), and submit the following response to the ERA's transmission growth capex draft decision (see Table 6.4).

Table 6.4: Revised AA4 proposal on transmission growth – capacity expansion capital expenditure ($ million real, June 2017)

Transmission capex amendment	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
CBD substation	62.2	0.0	0.0	Western Power has made this adjustment to transmission growth capex, and has also removed distribution growth capex associated with the CBD substation work from the AA4 forecast RAB.
Picton-Busselton 132 kV line	19.2	0.0	19.2	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB

418. These transmission capex amendments are discussed in the following sections.

6.2.1.2.1 CBD substation

419. Following the submission of the AA4 proposal, Western Power notified the ERA and GHD that it had reviewed the need for the proposed CBD substation in light of updated 2017 load forecast for the East Perth and CBD load areas. The reduced load forecasts have alleviated several capacity constraints in the area, leaving only a minor N-2 network capacity shortfall.

420. Given the updated load forecast, and as part of the Regulatory Test for the new Hay to Milligan Street 132 kV cable[98], we consider the CBD substation can be deferred beyond the current ten-year investment plan.

421. We have therefore removed $62.2 million from the AA4 transmission capacity expansion capex forecast. We have also adjusted the forecast for distribution capacity expansion to remove $14.5 million of distribution expenditure works related to the proposed CBD substation.

422. With the exception of removing the CBD substation expenditure, Western Power considers the revised 2017 demand and customer number forecasts have no material impact on the transmission capacity expansion growth forecasts submitted in the AA4 proposal.

6.2.1.2.2 Picton-Busselton 132 kV line

423. In its technical review, GHD recommends the forecast $19.2 million expenditure to convert the existing 66 kV line between Picton and Busselton to 132 kV line should be excluded from the AA4 forecast RAB on the basis that:

> *We do not accept that the justification included in the AA4 forecast capital expenditure is sufficient for this project to be included in the current portfolio. We invite Western Power to provide additional information to support this project, particularly as it relates to the asset*

98 Approved in 2018.

condition assessment of the existing PIC-PNJ/BSN 66 kV line and other 66 kV assets, and any network security issues relating to the Picton South area due to a bushfire contingency.[99]

424. GHD's commentary in its technical review suggests it considers there is a need for investment in the Busselton area, however, additional information on this project is required to supplement what was provided in the AA4 proposal.

425. Further analysis of the need for the Picton-Busselton line upgrade was conducted in late 2017, after the AA4 proposal was lodged. A summary of this analysis is provided below and a copy of the strategy report is available on request.

426. The transmission network south of Picton is supplied by a single 132 kV line and two 66 kV lines via two 132/66 kV transformers from Picton Terminal. Western Power's *2017 Annual Planning Report* identified a number of emerging limitations in the Bunbury load area, including at Picton (PIC), Busselton (BSN), Capel (CAP), Margaret River (MR) and Westralian Sands (WSD) substations. Network limitations are related to asset condition issues (with power transformers at multiple substations and ageing 66 kV wood pole circuits), voltage recovery and collapse scenarios, and voltage capacity in the Picton South transmission network. These limitations are already evident and expected to worsen further in the coming years.

427. In late 2017, Western Power revised the Bunbury load area long-term strategy. We identified that merely refurbishing the two Picton T1 and T2 132/66 kV transformers would not resolve capacity issues. Both of these transformers are in poor condition and have an expected remaining life of less than five years.

428. If both transformers fail, there is limited capacity to maintain supply to the 66 kV zone substations in the area. To mitigate the asset condition risk as well as voltage stability constraints, the long term strategy is to convert the existing 66 kV line between Picton and Busselton to 132 kV.

429. Several investment options were considered as part of the strategy:

1. retain 66 kV – this is essentially the 'business as usual' option where all existing network assets would be replaced at their existing operational voltage, albeit in some cases with a higher thermal rating
2. staged 132 kV development (Option A) – where specific transmission assets would be replaced with 132 kV specification components while retaining other assets at 66 kV
3. staged 132 kV Development (Option B) – largely the same as the Staged 132 kV Option A but installing the new 132 kV plant and equipment in different locations.
4. no action – no proactive replacement, only reactive
5. demand side management – opportunity for non-network solutions to defer replacement.

430. If no action was taken, these assets would be treated via piecemeal and reactive replacement upon actual or imminent failure. The approach would not address existing supply limitations, including dynamic voltage recovery issues, which would only be exacerbated as a result of load growth. It would also not address the existing and emerging poor asset condition across a number of locations and assets in the Bunbury load area.

431. The overall cost of piecemeal/reactive replacement is also likely to exceed that of the network options. Therefore option 4 has been discounted as it does not proactively address existing network risks and ultimately results in an increasing level of risk for no apparent cost saving over the other options considered.

[99] Page 164, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

432. Similarly, there is no realistic demand side management (DSM) option as the majority of the investment drivers are related to asset replacement. Demand aspects are only relevant here in relation to Capel substation and the network voltage recovery issue at the southern end of the 66 kV network during transmission outages.

433. In the case of Capel substation, the limitation is already present. Therefore DSM, which at best would have only a minimum impact for loads in the Capel area, would not defer the transformer capacity upgrade. In the case of the southern end voltage recovery issues, while DSM could potentially lead to a small reduction in the southern Picton network area demand, there is no guarantee the benefit obtained will occur at the time of any transmission outage that causes a voltage recovery issue. On this basis DSM as a standalone option has been excluded from further analysis.

434. A technical and financial analysis has been undertaken for the three viable network investment options. This includes consideration of the practical, environmental and decommissioning costs associated with the individual project work elements. All stages within each of the three network options up to 2030 have been explicitly considered within the financial analysis and a net present cost (NPC) has been calculated.

435. The option with the lowest capital cost was the 'retain 66 kV' option although the 132 kV Option A demonstrates the lowest NPC. The incremental difference in NPC between the two staged 132 kV development options is only three per cent. This suggests that depending on the final detailed design requirements, any one of the three options could represent the lowest cost investment strategy. On this basis, we have also considered the non-financial aspects of each option:

- **retain 66 kV** – this option is not aligned with the preferred long term strategy for the Bunbury load area or the wider Western Power Network (i.e. to remove 66 kV as a transmission operating voltage). By committing to retaining 66 kV for the foreseeable future, the existing voltage recovery issues will require ongoing management as area load continues to increase, particularly in Margaret River. Even though such load increases are likely to be relatively slow, this will necessitate further capital investment in reactive compensation plant to continue to manage this issue and ultimately may become the limiting factor supporting how much area load can be practically supplied by the network
- **132 kV Option A** – as with the alternative 132 kV scheme, this option will address the existing network issues, including voltage recovery performance. It can be complemented with a further upgrade of the remaining 66 kV network assets to 132 kV as part of a long term strategic development. This will align with both the Bunbury load area strategy objectives as well as the broader Western Power strategic objective to remove 66 kV equipment.

  The principal difference between this and option B is that the new 132/66 kV transformer will be installed at Picton as a replacement for the existing T1 unit. This in-situ replacement presents concomitant security of supply risks during the replacement (i.e. when operating with a single remaining 132/66 kV transformer unit at Picton). These risks could be managed to some extent by installing the new transformer off-line with new 132 kV and 66 kV switchgear and then the original T1 unit being removed. The additional cost of this plant would mean that the total capital cost would essentially be the same as the 132 kV Option B. However, it would still have the limitation that this new T1 transformer would need to be relocated to Busselton at some point in the future when the second 66 kV transmission line between Picton and Busselton (via Capel) is upgraded to 132 kV
- **132 kV Option B** – similarly to Option A, this would align with both the Bunbury load and wider Western Power strategic objectives, including the phased removal of 66 kV network assets. As the new 132/66 kV transformer would be installed at Busselton from the start of the option development, there would be no long term need to relocate the transformer.

  This option will also allow the maximum useable lifetime to be extracted from the existing Picton T1 and T2 132 / 66 kV transformers without jeopardising load area supply security.

436. Considering the above and given the minimum incremental NPC, the recommended approach is to proceed with the staged conversion of the Picton South Area network from 66 kV to 132 kV, with the exception of the MR substation.

437. The following works will be undertaken in the AA4 period as part of Stage 1:

- swap the WSD site connection from the existing PIC-CAP/WSD 71 66 kV overhead line to the PIC-CAP 72 66 kV overhead line
- upgrade the PIC-CAP 71 66 kV overhead line to 132 kV specification i.e. to PIC-CAP 81
- perform earth wire replacements on various PIC-CAP-BSN 66 kV and 132 kV circuits
- replace existing T1 66 / 22 kV 19 MVA transformer at Capel with a new voltage configurable 132 (66) / 22 kV 33 MVA transformer. Replace existing T1 66 kV circuit breaker with new 132 kV transformer circuit breaker (initially energised at 66 kV)
- add a new 132 / 69 kV 100 MVA transformer at Busselton with new 132 kV and 66 kV transformer circuit breaker bays
- replace T5 66 / 22 kV 27 MVA transformer at Picton with 132 / 22 kV 33 MVA transformer. Add new T5 132 kV transformer circuit breaker bay at Picton.

438. On the basis of this further information, we submit that the $19.2 million forecast capex for the Picton-Busselton line is sufficiently justified, is reasonably expected to satisfy the requirement of the NFIT, and should be included in the AA4 forecast RAB.

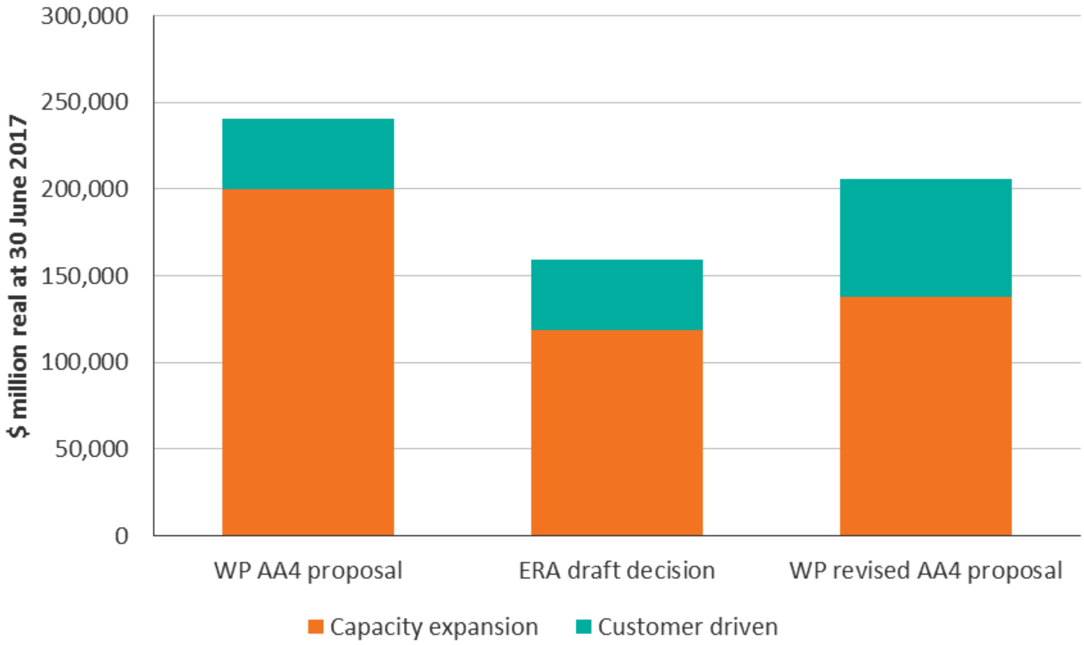
6.2.2 Forecast transmission growth capital expenditure

439. Taking into consideration the ERA's draft decision and the resulting adjustments to forecast capital expenditure, the revised AA4 forecast transmission growth capital expenditure is presented in the following table.

Table 6.5: Revised AA4 proposal on transmission growth capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Transmission growth capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Midwest	0.3	0.1	0.0	-	-	0.4
Supply	18.6	20.2	10.0	25.7	12.5	86.9
Thermal management	0.7	0.5	0.4	0.6	7.7	9.8
Voltage	5.5	5.0	21.8	5.4	2.8	40.5
Total capacity expansion	**25.1**	**25.7**	**32.2**	**31.7**	**22.9**	**137.6**
Customer access	12.3	22.4	15.2	9.0	8.9	67.9
Line relocations	-	-	-	-	-	-
Total customer driven	**12.3**	**22.4**	**15.2**	**9.0**	**8.9**	**67.9**
Total growth	**37.5**	**48.1**	**47.5**	**40.7**	**31.8**	**205.5**

Figure 6.6: Comparison of transmission growth capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.2.3 Transmission asset replacement and renewal

440. In its draft decision, the ERA excludes $114 million of Western Power's forecast transmission asset replacement and renewal capex from the AA4 forecast RAB. Following advice from its technical consultant GHD, the ERA removes the following expenditure items from the AA4 forecast:

- $20.4 million for power transformers
- $20.1 million for protection systems
- $30.1 million for switchboards
- $7.0 million for primary plant.

441. Despite GHD's recommendation that the West Kalgoorlie static VAR compensator (SVC) replacement should be allowed in AA4, and advice from the AEMO that *the replacement of the West Kalgoorlie and Merredin Terminal static VAR compensators is critical to the delivery of reliable power and power quality to customers in those towns*[100], the ERA removes $36.2 million of forecast capital expenditure for SVC replacement on the grounds that:

> *Given this is an area where planned investment has been deferred in the past, the ERA is particularly concerned that only projects that are reasonably likely to proceed during AA4 are included in the forecast expenditure.*[101]

442. Table 6.6 shows the ERA's forecast capex amendments.

[100] Paragraph 406, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[101] Paragraph 408, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Table 6.6: Draft decision transmission asset replacement and renewal capital expenditure ($ million real, June 2017)

Transmission asset replacement and renewal capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Western Power AA4 proposal	35.1	58.9	48.0	47.4	55.8	245.2
Power transformers	(1.6)	(5.5)	(5.0)	(3.6)	(4.7)	(20.5)
Protection	(4.6)	(3.9)	(3.9)	(3.9)	(3.9)	(20.1)
Switchboards	(2.4)	(6.6)	(5.8)	(6.3)	(9.0)	(30.1)
Transmission primary plant	(1.2)	(1.5)	(1.8)	(1.2)	(1.2)	(7.1)
Static VAR compensator	(7.5)	(11.5)	(1.8)	(7.5)	(7.9)	(36.2)
Draft decision	**17.7**	**29.8**	**29.8**	**24.9**	**29.1**	**131.2**

Source: Table 50, ERA draft decision

443. We have reviewed the ERA's reasoning for these amendments, along with the advice provided in the ERA's technical consultant's report (GHD's technical review), and submit the following response to the transmission asset replacement capex draft decision (see Table 6.7).

Table 6.7: Revised AA4 proposal on transmission asset replacement and renewal capital expenditure ($ million real, June 2017)

Transmission capex amendment	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Power transformers	52.4	32.0	52.4	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB
Protection	40.3	20.1	40.3	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB
Switchboards	67.4	37.3	67.4	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB
Transmission primary plant	46.8	39.7	46.8	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB
Static VAR compensator	36.2	0	22.2	Western Power accepts that some of this capex can be deferred, but submits further information to support inclusion of some of this forecast capex in the AA4 forecast RAB

444. These transmission capex amendments are discussed in the following sections.

6.2.3.1 Power transformers

445. There are 342 in-service power transformers in the Western Power Network. Western Power manages these transformers using condition based risk management methodology.[102] The AA4 proposal provided for capex to address 36 of the 90 transformers currently assessed as being in poor condition.

446. Western Power's optimised plan includes:

- refurbishing 14 transformers
- replacing three transformers
- decommissioning 19 transformers
- reconfiguring the network and installing two new transformers.

447. In addition to the above, Western Power's plan to mitigate the risks associated with the fleet of poor condition transformers involves using rapid response and spare transformers as required. The asset replacement regulatory category includes investment allowance for one reactive replacement, two strategic spares and one mobile transformer. One reactive replacement has already been undertaken during 2017/18, in response to transformer failure at Picton Substation, which was one of the 90 transformers assessed as in poor condition.

448. The asset replacement regulatory category also includes preliminary works to address seven transformers that will be replaced early in the AA5 period.

449. The ERA's technical consultant GHD states:

> *We agree that the overall approach is reasonable with refurbishment being able to resolve some of the issues and deferring full replacement cost which is both an economic solution, allows more timely action to improve the asset and avoids long duration security risks with outages.*[103]

450. Therefore, the technical suitability and prudence of the transformer replacement program appears not be in question.

451. However, GHD states in its report that:

> *Detailed business cases and condition reports supporting the proposed CAPEX of $52.4 million (direct costs only) for power transformers were not available to us at the time of this review.* [104]

452. GHD also adopts *a conservative view that 15% of the proposed replacements could be deferred with appropriate maintenance and repairs until AA5.*[105] And that:

> *In addition, based on our market data and an assumed scope of work, we would suggest further a 30% reduction in this area as available to Western Power through "… efficiencies identified during project development and implementation" as stated in their submission.* [106]

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102 Western Power's CBRM methodology and risk based approach to asset management has been an area of focus of ERAs asset management system reviews in 2014 and 2017. The 2017 ERA AMSR found that "Western Power's risk approach to renewal planning can be considered amongst industry leaders."

103 Page 141, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

104 ibid.

105 ibid.

106 ibid.

453. GHD subsequently recommends a 40 per cent reduction to the forecast. We are unclear on the evidence GHD has used to form the basis for this recommendation.

454. The AA4 transmission capital expenditure forecasts are based on least cost options and are subject to a stage-gate governance process. Detailed business cases are available depending on the stage of the investment governance process the project has passed through. To summarise:

- **post gate three** - detailed business cases are produced for projects that are in the planning or execution phase. This stage includes options analysis, +/-10% estimated costs, value assurance benchmarking analysis, and demonstration of compliance with the NFIT. Approximately 35 per cent of the AA4 transformer asset replacement forecast is at or beyond gate three
- **prior to gate three** - detailed business cases are not prepared, however documentation such as asset/network strategies, condition assessment reports, long term development plans, works planning reports, power system studies/analysis, and design advice documents are available to help inform the estimated timing and project cost.

455. Specific business cases on transmission transformer replacement were not provided to GHD during the course of its review as these were not included in the list of business cases selected by GHD and were not subsequently requested by GHD. Business cases for projects that are post gate three can be provided to the ERA upon request.

456. Though no business cases were requested, information on transformer condition was provided to GHD (and the ERA) as part of its review process. Western Power's *Power Transformer Strategy* was provided to GHD and the ERA on 7 November 2017.[107] The document provides details of Western Power's transformer assets and includes information on:

- asset age
- current condition
- risks and risk mitigation options
- maintenance and replacement strategy.

457. It is unclear whether GHD factored the *Power Transformer Strategy* into its consideration of transformer replacement volumes requiring treatment in AA4, however, all of the transformers selected for replacement and or decommission are in either bad or poor condition (and are more than 50 years old). Furthermore, the AA4 investment only addresses 40 per cent of the known poor condition transformers.

458. We do not consider it appropriate to defer 15 per cent (GHD's conservative estimate) of the proposed works into the AA5 period, as to do so would considerably increase the risk associated with transformer failure. Further, we consider a 40 per cent reduction in expenditure on power transformers would exacerbate the risk and be unsustainable.

459. Deferring the proposed investment would:

- increase the number of untreated bad/ poor transformers in service during the AA4 and AA5 periods
- increase reliability (network security), compliance (noise), safety (workforce) and reputation risk exposure
- reduce benefits from adopting an optimised transformer management plan that delivers risk treatment of 22 transformers through installation of only 7 new transformers and decommissioning of 15 transformers

107 Information request GHD007.

- increase the need for reactive replacement expenditure, which is a more expensive alternative than planned expenditure and will utilise a significant portion of labour resources impacting other planned works, as demonstrated by the Muja BTT1 and Muja BTT2 failures during AA3.

460. With regard to GHD's view that Western Power could find a *further 30 per cent reduction in this area through efficiencies identified during project development and implementation*, we consider this assumption to be unfounded.

461. Site specific investigations and scope refinement in many cases could mean costs will be higher than initially estimated, and our post gate three analysis indicates likely cost increases for transformer replacement rather than reductions.[108] In light of this, the likelihood of Western Power being able to achieve GHD's 30 per cent cost reduction assumption is low.

462. As a result, we maintain that the originally-forecast $52.4 million for transmission power transformer replacement will be delivered, is reasonably expected to meet the requirements of the NFIT, and should be included in the AA4 forecast RAB.

6.2.3.2 Protection

463. Forecast capital expenditure on protection replacement for the AA4 period is $40.3 million. As described by GHD in its technical review:

> *The key strategy is assessing condition through routine visual inspections, testing and remote monitoring. Currently, approximately 36% of the protection relays have been in-service beyond their nominal asset life. This is projected to increase to 50% by 30 June 2022 and 61% by 30 June 2027 without proactive replacement. For protection relays, Western Power has assessed a low risk on the reliability of the network and a medium risk with regards safety.*[109]

464. Based on GHD's recommendations, the ERA excludes 50 per cent of the forecast protection replacement capex. Though GHD accepts that the low level of expenditure during the AA3 period ($5.1 million) would necessitate an increase in AA4, it considers that the magnitude of the AA4 increase ($35 million) has not been sufficiently justified.

465. We accept that the increase in forecast expenditure compared to AA3 spend represents a substantial step change, however, the need for accurate, stable and reliable protection systems should not be understated.

466. GHD notes in its review that *Western Power has assessed a low risk on the reliability of the network.*[110] We are unclear how GHD formed this view as Western Power's Network Management Plan, which was provided to the ERA and GHD, demonstrates a reliability risk rating of medium for protection and control systems.

467. Protection systems are required to clear faults on the network and to maintain network reliability and stability. They also help limit damage to the network and mitigate safety risks. As correctly highlighted by GHD, a significant volume of protection devices are beyond their mean replacement life (MRL) and this number is likely to increase if proactive action is not taken.

468. Many of these protection devices use electromechanical technology, which does not provide for self-monitoring and does not provide the level of post fault information that the numerical relays provide. In the event of protection device failure inoperable devices will remain unnoticed until a network incident

[108] We do not propose to increase the AA4 capital expenditure forecast to accommodate these power transformer cost increases.
[109] Page 146, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.
[110] Page 145, ibid.

arises or the faulty devices are detected during routine testing. The electromechanical protection devices also no longer have manufacturer support and are obsolete, with minimal spares.

469. Failure of protection devices have been known to cause major power system events around the globe triggering a relay replacement program as a result. Western Power's strategy is to undertake replacement of protection systems prioritised by information on their condition and criticality of the asset that they are protecting, while taking into consideration a medium to long term view of the network.

470. We estimate 25 per cent of main protection relays on the network are subject to performance and obsolescence issues. Of these:

- ~45 per cent protect 132 kV and above assets:
  - ~75 per cent of these relays are above their MRL
  - ~86 per cent of these relays provide critical protection functionality for busbars, transformers or lines.

471. The expenditure levels proposed in the ERA's draft decision, would require Western Power to defer replacement of relays that protect busbar, transformer and lines circuits. This would increase the risk of protection failure, resulting in increased safety and reliability risk for critical portions of the network.

472. Therefore, as a prudent asset manager, we submit that the full $40.3 million investment is required and will be undertaken during the AA4 period.

473. With regard to deliverability, Western Power has the capability to deliver the increase in replacement volumes forecast for AA4. We have established a dedicated project team to manage the AA4 delivery. The business case for $24 million investment has been approved for the protection and auxiliary system (AC and DC system) replacement program over the 2017/18-2019/20 period in line with Western Power's Investment Governance Framework. This program is currently in the implementation phase.

474. Given that 60 per cent of this program is scheduled for implementation in the first three years of the AA4 period, we consider the overall program is deliverable.

6.2.3.3 Switchboards

475. There are 137 switchboards located at zone substations across the network. Five of these switchboards are beyond their MRL. If replaced only on failure, the number of switchboards beyond their MRL is likely to increase to ten per cent by 30 June 2022 and 12 per cent by 30 June 2027.

476. Seventeen switchboards use pitch-filled design, which has known failure modes that can lead to catastrophic failure. These switchboards are installed in 11 substations and present a high safety risk of arc flash exposure and associated power system reliability impacts. In line with our Electricity Network Safety Management System, the risks associated with these pitch-filled switchboards will be addressed through their progressive replacement as a part of an optimised plan, which includes:

  - replacing 11 switchboards during the AA4 period
  - decommissioning five switchboards during the AA4 period and one in AA5.

477. Until the switchboards are replaced or removed, interim steps to mitigate risks include implementation of various operational measures including special work practices.

478. A further nine switchboards are approaching their MRL and are no longer supported by their manufacturers (Yorkshire and GEC). We do not have adequate spare parts for repair or replacement to maintain them. Our

strategy is to replace two of these nine switchboards in AA4 and two in early AA5. A significant portion of the costs for the two switchboards to be replaced in early AA5 will be incurred during AA4.

479. In the AA4 proposal, we forecasted $67.4 million of capital expenditure to:

- replace 13 switchboards (11 pitch-filled)
- plan, scope and procure two switchboards planned for replacement in early AA5 including a minor cost for preliminary work for further two switchboard replacements
- establish one mobile ring main unit solution as a precaution in case any of the poor condition switchboards and/or those no longer supported by the manufacturer fail before they are replaced.

480. In its technical review, GHD raises no objection to the need to treat the switchboards as proposed, recognising that catastrophic failure of switchboards presents a safety and serviceability risk. However, GHD questions the accuracy of the cost estimates, considering they may be overstated.

481. In particular, GHD questioned the costs for replacing switchboards at Manning Street, Osborne Park and Yokine. GHD considers the costs of replacing single switchboards at these sites appear excessive when compared with the cost of replacing what it assumes are four switchboards at the Milligan Street and Hay Street sites in Perth's Central Business District. GHD concluded that if four switchboards can be replaced at Hay Street for around $2.5 million each, then around $5 million to replace one switchboard at Osborne Park must be overstated.

482. However, there are in fact **only two switchboards** at the Milligan Street and Hay Street sites.[111] As a result, the individual switchboard replacement costs for Hay Street are approximately $5 million per switchboard. This is in line with the Manning Street, Osborne Park and Yokine estimates.[112]

483. The estimated cost of replacing a single switchboard is typically around $5 million. The average cost of replacing the obsolete Yorkshire and GEC assets is estimated to be slightly more per switchboard. While GHD has correctly identified that two Yorkshire/GEC switchboards will be replaced in full during the AA4 period, the assumption that the remaining costs only relate to preliminary work on two other switchboards is incorrect.

484. The expenditure profile for the AA4 period is staggered so that while only two switchboards will be replaced in full during the period (with replacement works commencing in 2018/19), replacement of two further switchboards will commence in 2019/20, with these works to be completed in the first year of the AA5 period. Therefore, the majority of expenditure for replacing these two additional switchboards will be incurred during the AA4 period. The AA4 forecast also includes the preliminary works on a further two switchboards. Table 6.8 shows the staggered expenditure profile.

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111 Physically, there are only two switchboards per site at Hay Street and Milligan Street respectively (total switchboards = 4). However, each of these units comprises two separate sections connected via a bus section CB (total sections = 8). In Western Power's internal asset management systems, these switchboards have been registered based on their electrical configuration (i.e. total of 8 sections). As such, some Western Power documentation may refer to eight total switchboards at Hay Street and Milligan Street respectively – this is however based on the electrical configuration, not the physical number of switchboards.

112 As is the case with power transformers, Western Power is finding that site specific investigations and scope refinement in some cases reveal higher costs than initially estimated. However, we do not propose increasing the AA4 capital expenditure forecast to accommodate these higher costs.

Table 6.8: Yorkshire/GEC switchboard expenditure profile ($ million real, June 2017)

Number of Switchboards	AA4 period					AA5 period
	17/18	18/19	19/20	20/21	21/22	22/23
2		0.2	2.9	6.6	1.7	
2			0.2	2.9	6.6	1.7
1				0.1	1.4	3.3
1					0.1	1.4

485. Finally, GHD also considers the cost estimates for reactive replacements seems high. We presume this again is due to its underestimation of the average cost of replacing a single switchboard.

486. The AA4 proposal provided for three reactive replacements over ten years at a cost of $6.4 million per switchboard, equivalent to 1.5 replacements over the AA4 period or $9.6 million. The provision for three failures per decade was based on historical failure rates, as well as existing asset condition assessments.

487. Reactive replacement cost estimates are typically higher than proactive switchboard replacement forecasts. This is due to the number of unknowns such as site complexity, contingency costs, on-call labour costs and the potential for collateral damage in the event of catastrophic failure.

488. As a result, we consider the total $67.4 million capital expenditure forecast for transmission switchboard replacement is not overstated, is reasonably expected to meet the requirements of the NFIT, and should therefore be included in the AA4 forecast RAB.

6.2.3.4 Transmission primary plant

489. In the AA4 proposal, we estimated $46.8 million of capex is required for replacing and renewing transmission primary plant. These works include replacement of circuit breakers, disconnectors, earth switches, instrument transformers and surge arrestors.

490. In its technical review, GHD endorses the need to address primary plant issues, stating:

> *We agree with the approach taken by Western Power in monitoring condition through routine inspections and repair/ treat defects prioritised by risk.*[113]

491. However, GHD has challenged the $46.8 million forecast replacement/renewal costs, stating:

> *We would expect some efficiencies through business transformation and greater efficiency in delivery and would recommend an allowance of $39.74 million, assuming a 15% efficiency through improved delivery.*[114]

492. We consider GHD's 15 per cent efficiency assumption is arbitrary, and the likelihood of Western Power being able to achieve cost savings of that magnitude is low. This is because the unit rates used for the AA4 forecast were based on AA3 actuals, which already include efficiencies through economies of scale.

493. We achieve these economies of scale by completing as much work a possible during an outage on a given site, and bundling as much work as is reasonable to do so. However, as endorsed by GHD, our asset management approach is based on treating defects prioritised by risk rather than pursuing higher volumes of replacement at lower costs. Put simply, our aim is to address the highest risk circuit breakers and other

[113] Page 142, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.
[114] Ibid.

primary plant first, and while we will always seek to combine works to achieve economies of scale, the scope to do so is limited.

494. We therefore consider the $46.8 million represents efficient costs and is reasonably expected to meet the requirements of the NFIT. We have therefore included this capital expenditure in the AA4 forecast RAB.

6.2.3.5 Static VAR compensators

495. There are three SVCs located at terminal substations in the Western Power Network:

- West Kalgoorlie Terminal Substation
- Merredin Terminal Substation
- Southern Terminal Substation.

496. In the AA4 proposal, we submitted $36.2 million of forecast capex to replace the SVCs at West Kalgoorlie and Merredin. There are currently no plans for replacing the Southern Terminal SVC in AA4 or AA5. As GHD highlights in its report:

> *The investment in replacement of two of these SVCs has been deferred over the last two regulatory periods and the condition of these SVCs is considered to be poor leading to reliability issues.*[115]

497. Though GHD has not disputed the need to replace the SVCs, it has challenged the forecast costs of replacing them, which it considers should be approximately $14.6 million for West Kalgoorlie.

498. GHD's cost estimate assumes the scope of the West Kalgoorlie replacement is limited to two 8 MVAr capacity units. However, the actual scope involves far more. Table 6.9 shows the full West Kalgoorlie scope.

Table 6.9: West Kalgoorlie Terminal Station SVC replacement project scope ($ million real, June 2017)

Stage	Description	Estimated cost
1	• Install and commission 220kV tapped shunt reactors and STATCOMs at Boulder and West Kalgoorlie • Design and install an independent master controller (IMC) to coordinate with the STATCOM controllers to be supplied by the STATCOM manufacturer • IMC to control the capacitor banks, reactor banks at West Kalgoorlie Terminal (WKT), Boulder (BLD), Piccadilly (PCY) and Black Flag (BKF) and transformer tap positions at WKT	[redacted]
2	• Decommission and remove WKT SR2 and all components including associated controller and retain WKT SR1 including harmonic filters, slope correction capacitors and controller	[redacted]
3	• Install and commission two, 29.5kV 17.5 MVAr air core shunt reactors. Both reactors connected off from WKT T2 tertiary.	[redacted]
4	• Decommission and remove WKT SR1 and all components including associated controller	[redacted]
General	• Project management	[redacted]
Total		[redacted]

[115] Ibid.

499. As shown above the scope referred to by GHD only forms part of the Stage 1 works. The full scope of works across all project stages are essential to address the reliability and power quality risk associated with not replacing the West Kalgoorlie SVC.

500. It is worth noting that GHD has not disputed the network need for the West Kalgoorlie SVC replacement. The AEMO also makes clear the need for the West Kalgoorlie and Merredin SVCs in order to maintain delivery of reliable power and power quality to customers in those areas. Despite this, the ERA disallows the full $36.2 million of forecast capex from the AA4 forecast RAB.

501. The ERA cites concerns that the SVC projects may not proceed during the AA4 period as these projects have been deferred in the past. We understand the ERA's caution, however, the West Kalgoorlie SVC replacement has been in execution since February 2017. The current project status is as follows:

- two of the three design packages have been completed and the main 220kV shunt reactor and STATCOM items are currently being manufactured
- the main civil package contract to extend the substation has been awarded
- the 220kV Shunt Reactor has been manufactured and is awaiting testing. The unit is scheduled to be delivered to site in September 2018 and commissioned by March 2019
- the STATCOMs are being manufactured. The units are scheduled to be delivered to site in July 2019 and October 2019 and commissioned by March 2020
- the balance of the works involve decommissioning the existing SVC equipment, which is scheduled to be complete by June 2021.

502. We consider the West Kalgoorlie SVC project is sufficiently progressed to give confidence to the ERA and customers that it will be delivered during the AA4 period as proposed. We therefore maintain that the forecast capex associated with the West Kalgoorlie SVC should be included in the AA4 forecast RAB.

503. Given the Merredin Terminal Station project is not scheduled to commence until 2020/21, we consider the replacement of this asset can be deferred unto the AA5 period. To mitigate the risk of reliability and power quality issues in the Merredin area, we will use available spares and salvaged parts from the existing West Kalgoorlie SVC and use them to manage and maintain the Merredin SVC during the AA4 period. In the event of a major failure at Merredin, the SVC will be replaced in full.

504. We have therefore revised the AA4 forecast capital expenditure on SVCs downwards from $36.2 million to $22.2 million.

6.2.4 Forecast transmission asset replacement and renewal capital expenditure

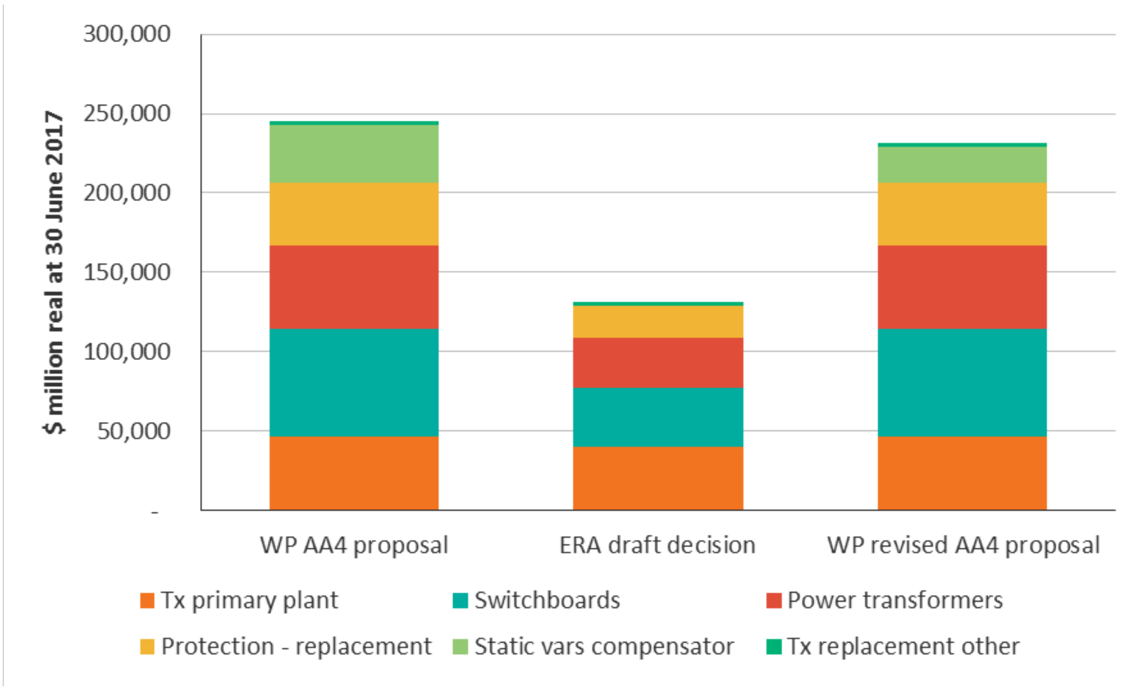
505. Taking into consideration the ERA's draft decision and the resulting adjustments to forecast capital expenditure, the revised AA4 forecast transmission asset replacement and renewal capital expenditure is presented in the following table.

Table 6.10: Revised AA4 proposal on transmission asset replacement and renewal capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Transmission asset replacement and renewal capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Primary plant	8.1	10.2	12.3	8.2	8.0	46.8
Switchboards	5.5	14.7	12.9	14.2	20.1	67.4
Power transformers	4.1	14.2	12.8	9.3	12.0	52.4

Transmission asset replacement and renewal capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Protection – replacement	9.3	7.8	7.7	7.7	7.7	40.3
Static VAR compensator	3.4	8.6	4.4	3.0	2.9	22.2
Tx replacement other	0.7	0.5	0.5	0.5	0.1	2.2
Total asset replacement and renewal	**31.0**	**55.9**	**50.6**	**42.9**	**50.7**	**231.2**

Figure 6.7: Comparison of transmission asset replacement and renewal direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.2.5 Transmission improvement in service

506. Forecast transmission improvement in service for the AA4 period is made up entirely of SCADA and communications investment. No capex on 'reliability driven' projects is included in the AA4 forecast RAB.

507. Western Power proposes to invest $89.9 million to replace obsolete SCADA and communications equipment and maintain the performance of system monitoring and control.

508. The ERA's technical consultant, GHD, advises:

> *…the current Western Power capital expenditure per circuit kilometre is well below the average expenditure for other industry participants and that the forecast expenditure in 2018/19 is more comparable with the industry average.*[116]

509. Further, GHD recommends:

> *Given that Western Power has changed its asset strategy for SCADA & Communications from a reactive to largely proactive, and that the existing network is aged, technical obsolete and lacking manufacturer support, we are of the opinion that the forecast AA4 expenditure*

116 Paragraph 412, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

allowances are "catch-up" to bring Western Power in-line with a majority of transmission electricity utilities in the Australian market. Whilst we have been unable to review the forecast CAPEX in detail, given the benchmarking study found that the proposed Western Power AA4 forecast expenditure is comparable to industry average CAPEX per circuit kilometre, we are of the opinion that the proposed CAPEX allowances for AA4 are reasonable.[117]

510. The ERA accepts that *the current assets are old and in many cases no longer supported by the vendor*, and that *reliable SCADA and communications are necessary to enable Western Power to effectively manage its network.*[118]

511. The ERA has therefore not adjusted the forecast transmission SCADA and communications expenditure in the draft decision. However, the ERA questions the deliverability of the investment and whether the proposed SCADA and communications upgrades are reasonably expected to occur in the AA4 period.

512. To deliver the increased SCADA and communications program of work over the AA4 period, Western Power has changed from a predominantly internal resource pool to a mix of internal and external resource delivery. During the AA4 period, Western Power will use internal resources for design and commissioning activities with the construction undertaken using external resources.

513. We have evaluated the market and have external delivery vendors in place. We work in partnership with these vendors to appropriately resource the delivery of activities. Where possible, we will give precedence to open source internet protocol technology over proprietary communications protocols when selecting new equipment.

514. To enable more efficient delivery of the program, we have moved away from developing discrete SCADA and communications projects, and now develop projects that group assets by location and technology type. Joint planning teams have been established across SCADA and communications and other regulatory categories to optimise the delivery of Western Power's overall work plan. This optimised delivery plan co-ordinates interventions on different asset classes to reduce travel costs and minimise network disruptions.

515. Several SCADA and communications projects are already in execution. These projects have passed gate three of Western Power's Investment Governance Framework and are supported by detailed business cases.

6.2.6 Forecast transmission improvement in service capital expenditure

516. Taking into consideration the ERA's draft decision and the resulting adjustments to forecast capital expenditure, the revised AA4 forecast transmission improvement in service capital expenditure is presented in the following table.

Table 6.11: Revised AA4 proposal on transmission improvement in service capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

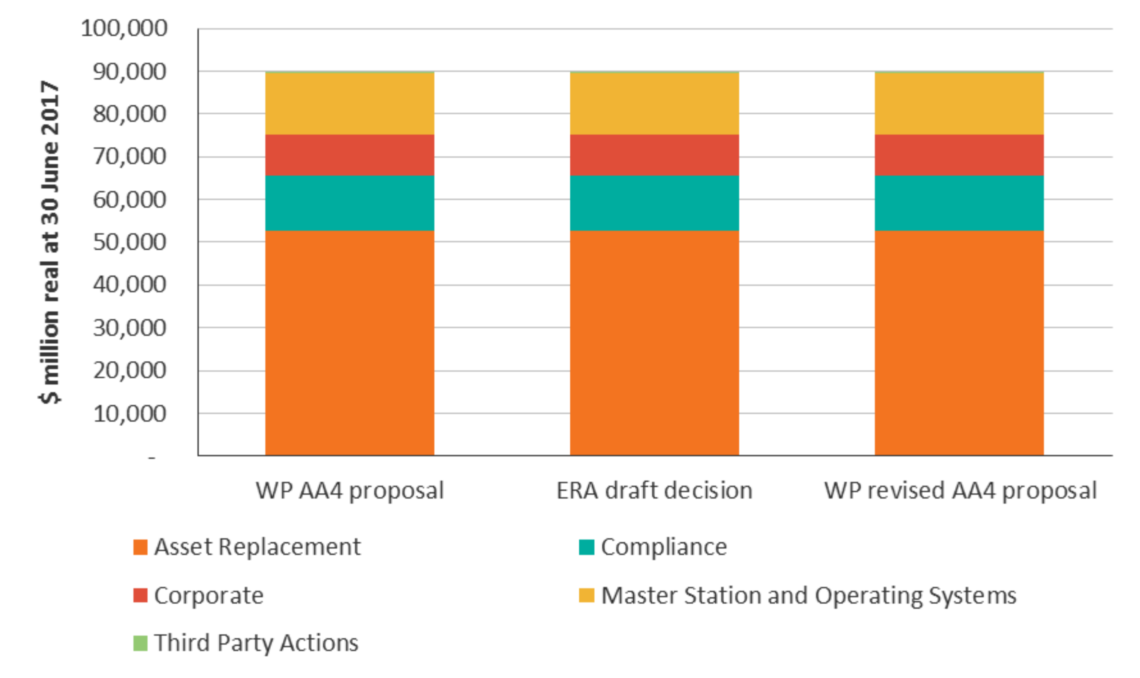
Transmission improvement in service capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Asset replacement	8.2	10.8	10.5	11.1	12.1	52.7
Compliance	0.4	2.0	4.1	3.6	3.0	13.0
Corporate	1.8	3.1	3.1	1.0	0.4	9.4

117 Paragraph 413, ibid.

118 Paragraph 414, ibid.

Transmission improvement in service capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Master station and operating systems	1.2	3.7	4.9	4.5	0.1	14.5
Third party actions	-	0.1	0.1	0.1	0.1	0.3
Total SCADA & communications	**11.5**	**19.7**	**22.8**	**20.2**	**15.6**	**89.9**
Total improvement in service	**11.5**	**19.7**	**22.8**	**20.2**	**15.6**	**89.9**

Figure 6.8: Comparison of transmission improvement in service direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.2.7 Transmission compliance

517. In the AA4 proposal, Western Power forecasted $155 million of capex is required to address transmission compliance requirements. The forecast included investment to replace transmission poles and towers, meet noise and fire safety compliance requirements, improve transmission protection systems, replace underground transmission cables and improve substation safety and security.

518. On the advice of its technical consultant GHD, the ERA considers the majority of this compliance-related capex is reasonably expected to meet the requirements of the NFIT and have therefore added $95.3 million to the AA4 forecast RAB.

519. The $59.7 million excluded from the RAB relates entirely to substation security, which includes investment in physical barriers and systems designed to deter, prevent and detect unauthorised access of Western Power's substations by the general public and unauthorised and/or unqualified staff. The ERA reduced the amount of substation security investment included in the AA4 forecast RAB from $72.1 million to $12.5 million.

520. Table 6.12 shows the ERA's forecast capex amendments.

Table 6.12: Draft decision transmission compliance capital expenditure ($ million real, June 2017)

Transmission asset replacement and renewal capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Western Power AA4 proposal	32.6	33.7	34.2	27.2	27.2	155.0
Substation security	(15.7)	(10.7)	(14.6)	(9.9)	(8.8)	(59.7)
Draft decision	**16.9**	**23.0**	**19.6**	**17.3**	**18.4**	**95.3**

Source: Table 53, ERA draft decision

521. We have reviewed the ERA's reasoning for the reduction in substation security investment, along with the advice provided in the ERA's technical consultant's report (GHD's technical review), and submit the following response to the ERA's transmission compliance capex draft decision (see Table 6.13).

Table 6.13: Revised AA4 proposal on transmission asset replacement and renewal capital expenditure ($ million real, June 2017)

Transmission capex amendment	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Substation security	72.1	12.5	64.1	Western Power has not made this amendment, and submits further information to support inclusion of a revised amount of substation security capex in the AA4 forecast RAB

522. The AA4 substation security requirements are discussed in the following section.

6.2.7.1 Substation security

523. The ERA's decision to exclude $59.7 million of substation security investment appears to be driven by its assumption that:

> *The increase in expenditure arises from Western Power's view that it must upgrade security for all substations in its network to comply with the National Guidelines for Protecting Critical Infrastructure from Terrorism, introduced in 2015.*[119]

524. The *National Guidelines for Protecting Critical Infrastructure from Terrorism* is not the primary driver for the substation security investment. Substation security capex is driven by the need to improve the fencing and associated security measures at a number of substations across the SWIS to prevent unauthorised entry to high voltage facilities, which can lead to public safety and power system security risks. By improving security at substations, we can help mitigate the risk of electric shock as well as copper theft and vandalism.

525. The substation security capex forecast is based on the outcome of a detailed risk assessment of fencing and security measures at all 155 substations on the Western Power Network. The condition risk assessment, conducted during 2016, identified that a large population of substation fences have an increasingly high likelihood of unassisted failures (i.e. bad and poor condition).

526. The *National Guidelines for Protecting Critical Infrastructure from Terrorism* is a useful driver to help identify which substations would result in the greatest network impact if they were to be subject to a

[119] Paragraph 418, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

terrorist attack (such as [redacted]), and prioritise these for treatment, however it is not the sole driver.

527. We have, however, reviewed the forecast substation security capex in the light of the ERA's draft decision and GHD's recommendations, and have revised the forecast downwards by $8 million to $64.1 million. This $8 million reduction is due to the deferral of three substation security projects until the AA5 period.

528. The substation security expenditure category includes a number of line items relating to safety and security-related works on substations and their grounds. This includes fencing and security measures, asbestos removal and roof replacements. The breakdown of forecast substation security investment during AA4 is shown in Table 6.14.

Table 6.14: Forecast substation security capex by activity ($ million real, June 2017)

Project / Program	17/18	18/19	19/20	20/21	21/22	Total
Substation fencing and security measures	7.7	9.0	12.0	8.3	7.4	44.4
Physical security systems	0.3	3.1	1.7	1.6	1.6	8.3
Building and ground works – asbestos	0.5	0.5	0.5	0.5	0.5	2.5
Building and ground works - roofing	0.5	1.9	2.5	2.0	2.0	8.9
Total	**8.9**	**14.6**	**16.8**	**12.3**	**11.5**	**64.1**

529. The line items in Table 6.14 are discussed in the following sections.

6.2.7.1.1 Substation fencing and security measures

530. Western Power will invest $44.4 million during the AA4 period to improve the fencing and physical security measures at the highest risk substations. In 2016, Western Power conducted a comprehensive review of its substations to determine the condition of security fencing. This review has been used to develop an asset treatment and replacement program over a ten-year delivery schedule, prioritised by risk.

531. The risk assessment considered the following factors:

- fencing MRL (which is 25 years)
- fencing condition
- asset profile analysis
- incident data analysis.

532. Based on these factors, each substation is given a risk rating.

533. The scope of work for fencing and physical security measures is aimed at deterrence, detection and response. The project covers all aspects of substation security from physical barriers (fencing, locks), signage, lighting and active security monitoring. The specific work required for each substation site is informed by the risk assessment outcomes and maintenance cost history.

534. Cost estimates for fencing are developed internally by Western Power using the same modelling, design, standards and governance as used for discrete network infrastructure investment. Cost estimates for electronic security is based on market prices and involves testing these with various trade experts.

535. We have identified 72 substation locations that require physical security treatments over the next ten years. The replacement/treatment schedule is informed by the following criteria (drawn from the substation risk assessment):

1. **asset condition (condition)** – we will prioritise substations with poorest condition fences, correlated against their MRL. We estimate four fences per year will need to be replaced to manage this ongoing risk
2. **critical site upgrades (criticality) -** security incidents in substations can result in forced outages due to loss or damage of the earthing system. Sites that would result in the highest network impact in the event of a forced outage will be prioritised for treatment
3. **high incident site upgrades (threat and vulnerability) -** incident data shows that 23 per cent (36) of sites have 89 per cent of the incidents. Sites with high incident frequency will be prioritised.

536. We apply a weighted approach applied to each of the criteria, these are:

- condition (60 per cent)
- critically (25 per cent)
- threat and vulnerability (15 per cent).

537. These criteria inform the risk treatment. For example, if a substation has an overall high criticality rating but its fencing is less than ten years old and in a good condition, then the fence would not be replaced. In this instance, other solutions will be implemented such as electronic security systems.

538. The top five highest priority risk substation projects are provided below.

- [redacted] – both substations have the highest prioritisation. This is because the substation fences are in a bad condition and have exceeded the MRL [redacted] have also experienced over 50 break-ins each over the past ten years.

  To mitigate the risk at these substations, we propose to completely replace the fences and include electronic security systems. Each project has already progressed to execution phase with an expected completion date of June 2018.
- [redacted] – fences at both locations exceed their MRL and are in a bad condition. On average, there have been more than ten security incidences per year, per site. We propose both sites will have a full fence replacement and electronic security systems implemented including cameras and motion sensors.
- [redacted] – this substation has a bad condition fence and is located at a moderately critical site. The site experiences an average of five break-ins per year therefore driving a medium threat result. As such, this site will receive a full fence replacement due to the bad fencing condition and minor electronic security system to address the criticality and threat risks. The project has progressed to gate three of Western Power's investment governance framework.
- [redacted] – this substation fence has exceeded the MRL and is in very bad condition. Although the site has a minor criticality for network operations, the fence condition is the main driver for a full fence replacement. As [redacted] experiences minimal break-ins, no extensive electronic security systems are required.

539. These are just some of the key sites scheduled for treatment. Over the AA4 period, we expect to address 37 sites.

540. Based on the risk criteria summarised above, combined with the rigours of Western Power's investment governance framework, we submit that the $44.4 million of capex forecast for this program is reasonably expected to satisfy the requirements of the NFIT and should be included in the AA4 forecast RAB.

6.2.7.1.2 Physical security systems

541. During the AA4 period, Western Power will invest $8.3 million in physical security systems across various sites.

542. Western Power's Property and Fleet Function is responsible for delivering appropriate security solutions and supporting the physical security needs of the organisation relating to personnel, telecommunications, depots, substations and primary and secondary systems.

543. Western Power engaged Jacobs Consultancy to conduct a security audit to identify primary security risks and develop a range of recommendations.[120]

544. The $8.3 million physical security systems forecast comprises investment activities to address these risks, and is distinct from the substation security investment described in section 6.2.7.1.1. The three major components of the physical security systems investment are:

1. security systems
2. physical access controls
3. key management project.

545. These are discussed in the following sections.

Security systems

546. Western Power's security systems are on their own internet protocol network, which is not managed by Western Power's Information and Communications Technology (ICT) function. The role of ICT in supporting security systems is only to manage the firewalls that segregate the security systems from the corporate network. The management and delivery of every component of the security systems IT infrastructure is administered by the Property and Fleet function. This includes hardware (servers, controllers, cameras) and software.

547. Investment in security systems during the AA4 period comprises two major components:

- **software updates and hardware replacement**

  By investing in new hardware and software the core security systems will remain compliant with business needs, increase functionality and allow for integration with new products such as data analytics

- **automating security systems**

  We will procure analytics systems that automatically analyse closed-circuit television (CCTV) footage for 'out of band' motion. These system will reduce the number of security guards required to manage the CCTV systems.

  Proposed controls for on-site high risk areas include new CCTV cameras covering black spots and new physical barriers around scrap copper bins and high risk storage areas. These physical security

[120] Western Power Physical Security Strategy – Security Risk Assessment Report 02 May 2016

solutions are not considered in the fencing treatment and replacement project, mentioned above, as they are required for security controls inside of the fencing perimeter. Risks posed by malicious or criminally motivated people, that bypass perimeter security controls, will be addressed by automated security systems and barriers in high incident areas.

Physical access controls

548. This activity comprises a two-phase approach that leverages existing IT solutions to increase security across all Western Power sites.

- **phase one: role-specific access**

  The role-specific initiative will identify all physical access requirements for each employees/contractors role in the organisation, and integrate the HR and Access Control systems.

  Currently, the onus is on the team leader to allocate the appropriate access requirements for each individual role. By implementing an automated and detailed role based system access approach, Western Power will provide consistent, standardised and transparent appropriate role-specific access solutions, increasing security for all personnel. This initiative will be delivered through a joint workforce from HR, ICT, Governance Risk and Compliance and Property and Fleet to ensure full and accurate coverage across the organisation

- **phase two: self-service system**

  The self-service system allows employees and contractors to self-manage physical access requests to locations outside of their designated role due to a specific business need. The self-service system will allow all employees to log a security access request, which will be processed using segregation of duties and approved workflows depending on the location requested (for example requests for access to the control centre would require security clearance and approval by the relevant Head of Function before access would be granted).

Key management project

549. The 2016 security audit identified issues with management of mechanical keys. Mechanical keys are the primary control to prevent unauthorised access to substations and equipment across the Western Power network, including pole top switches and ring main units.

550. Western Power's key patents are due to expire (after a 12 year period) during the AA4 period and therefore require replacement and upgrade. This provides an opportunity to review the requirement for mechanical keys and implement more efficient, secure and cost-effective measures.

551. The key management project will include initiatives such as introducing electronic key cabinets and replacing key barrels.

6.2.7.2 Building and ground works – asbestos and roofing

552. Western Power will undertake building and grounds work during the AA4 period at a cost of around $11.4 million. These works include:

- asbestos mitigation works including the removal of harmful substances and asbestos from materials such as roofs, gutters, downpipes, eaves, cables, conduits and capping material
- replacing roofs that have exceeded their MRL, are in a poor condition (based on an asset condition and risk assessment review) and pose unacceptable safety risk to Western Power personnel
- care and maintenance of all transmission substations building and grounds.

553. During 2017/18 Western Power conducted roof inspections and condition assessments in order to refine the roof replacement schedule and identify any expenditure or replacement work that could be deferred. The buildings and grounds roof replacement program will replace four roofs per year for 10 years based on the condition assessment and maintenance cost history. Many of the buildings have exceeded their economic life and are in various levels of decay requiring immediate roof replacements, such as Picton Depot with the roof collapsing in April and immediate remedial work underway.

554. We consider deferring any building and grounds expenditure would result in unacceptable risks to both Western Power personnel and the public with the potential to negatively impact network reliability as a secondary impact. The required building and ground works have been put out to contract and are expected to ramp up in 2018/19, to be delivered as forecast during the AA4 period.

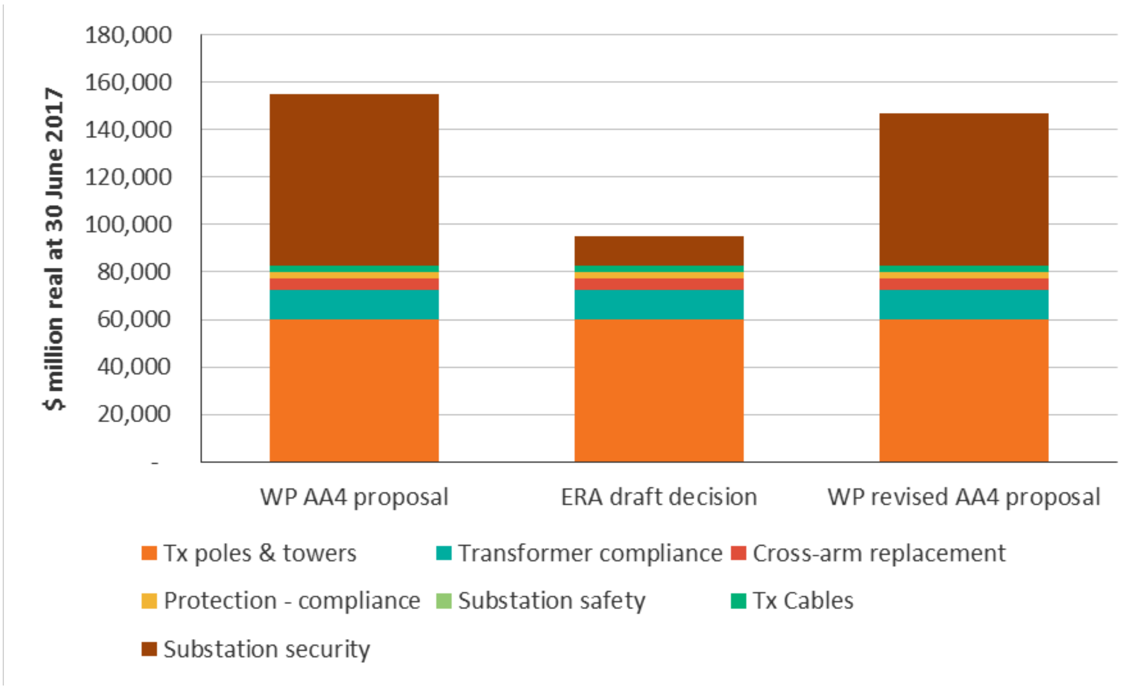
6.2.8 Forecast transmission compliance capital expenditure

555. Taking into consideration the ERA's draft decision and the resulting adjustments to forecast capital expenditure, the revised AA4 forecast transmission compliance capital expenditure is presented in the following table.

Table 6.15: Revised AA4 proposal on transmission compliance capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Transmission compliance capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Cross-arm replacement	1.0	0.9	0.9	0.9	0.9	4.8
Protection - compliance	0.5	1.8	0.0	-	-	2.3
Substation safety	0.0	-	-	-	-	0.0
Substation security	8.9	14.6	16.8	12.3	11.5	64.1
Transformer compliance	0.4	5.2	3.5	2.5	1.1	12.7
Cables	-	-	0.1	0.2	2.7	3.0
Poles & Towers	12.6	12.6	12.7	11.2	11.1	60.0
Total Compliance	**23.4**	**35.2**	**33.9**	**27.1**	**27.4**	**147.0**

Figure 6.9: Comparison of transmission compliance direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.3 Distribution capital expenditure

556. Forecast investment in the distribution network is significantly lower than that incurred during the AA3 period. This is primarily due to the lower forecast in wood pole replacement resulting from improvements in our asset management approach. Similar asset management improvements have been made in other areas of distribution asset replacement, such as conductor management. As such, during the AA4 period we consider we can maintain service levels and public safety for lower overall cost.

557. We have also acquitted the Energy*Safety* Order 2009-01, which required Western Power to address the safety risk associated with its rural wood pole population. As a result, wood pole management costs, which are typically one of the largest expenditure items for any overhead distribution network business, are notably less for AA4.

558. There are aspects of distribution investment that are increasing during the AA4 period, such as metering. This is driven by our advanced metering infrastructure program, which seeks to incrementally install advanced meters and associated IT and communications infrastructure over the AA4 period. This advanced metering program remains a key part of our distribution capex program for the AA4 period, and further information to support the IT and communications components of the advanced metering program is provided in this revised AA4 proposal.

559. Our revised AA4 distribution capex proposal, including our response to the ERA's amendments, is discussed in the following sections.

6.3.1 Distribution growth

560. The growth-related capex forecasts in the AA4 proposal were based on the 2016 demand and customer number forecasts. We have reviewed the forecast distribution growth-related capex in the light of the 2017 demand forecasts, and submit that, with the exception of distribution expenditure related to the CBD

substation, no change is required to the amount of forecast distribution growth new facilities investment for the AA4 period.

561. Distribution customer driven expenditure remains unchanged from the October 2017 AA4 proposal as the differences between the 2017 and 2016 demand forecasts have no material impact on distribution requirements.

562. Distribution capacity expansion expenditure has been adjusted downwards by $14.5 million to remove distribution investment related to the CBD (Milligan Street) substation, which is no longer required during the AA4 period. This adjustment is in accordance with the adjustment to transmission capacity expansion described in section 6.2.1.2.1.

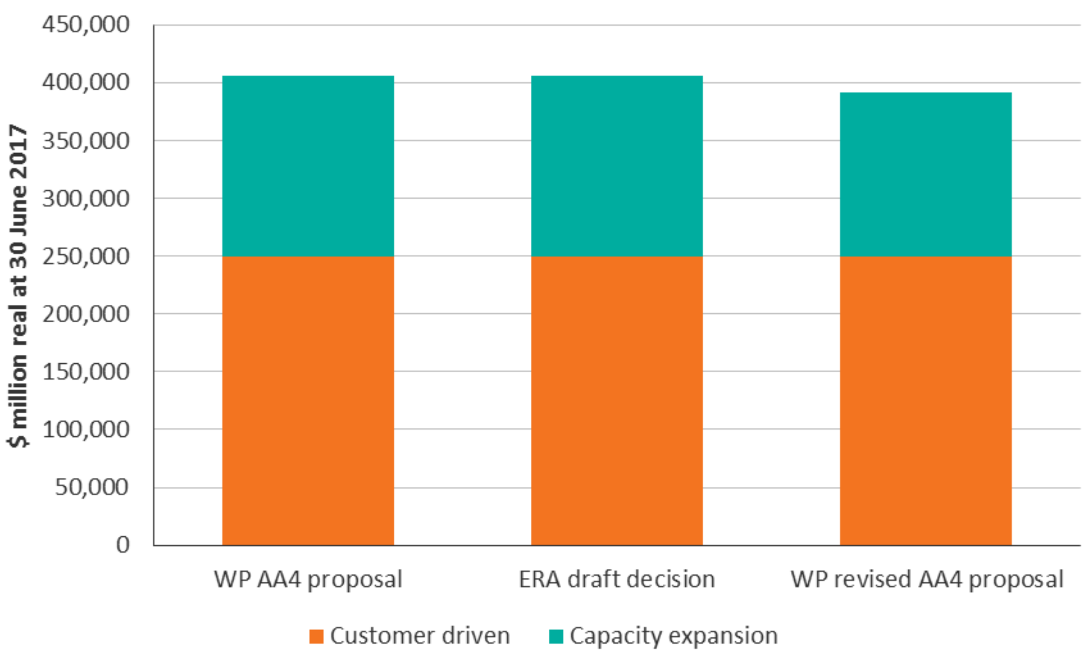
6.3.2 Forecast distribution growth capital expenditure

563. Taking into consideration the ERA's draft decision and the resulting adjustments to forecast capital expenditure, the revised AA4 forecast distribution growth capital expenditure is presented in the following table.

Table 6.16: Revised AA4 proposal on distribution growth capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Distribution growth capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
HV distribution driven	13.2	18.0	12.3	6.4	16.1	65.9
HV fault rating & protection	13.9	8.2	7.4	7.1	1.9	38.5
Overloaded transformers	3.6	3.6	3.6	3.6	3.6	18.0
Transmission driven	5.5	4.8	4.9	3.4	1.0	19.6
Total capacity expansion	**36.1**	**34.7**	**28.2**	**20.5**	**22.5**	**142.0**
Connection	4.8	4.8	4.8	4.8	4.8	24.1
Major capital	10.1	10.1	10.1	10.1	10.1	50.3
Network extension	26.1	26.1	26.1	26.1	26.1	130.7
Relocation	2.8	2.8	2.8	2.8	2.8	14.1
Subdivision	6.0	6.0	6.0	6.0	6.0	30.2
Total customer driven	**49.9**	**49.9**	**49.9**	**49.9**	**49.9**	**249.4**
Total growth	**86.0**	**84.5**	**78.1**	**70.4**	**72.4**	**391.4**

Figure 6.10: Comparison of distribution growth direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.3.3 Distribution asset replacement and renewal

564. In the AA4 proposal, Western Power forecasted just over $1 billion of capex is required for distribution asset replacement and renewal. This investment includes the costs of renewing and replacing Western Power's wood pole population, overhead (and underground) conductor, metering population and other distribution assets, and is a 26 per cent decrease compared to what was spent during the AA3 period.

565. In its draft decision, the ERA states it *is satisfied the proposed expenditure is reasonably likely to meet the new facilities investment test with two exceptions:*

- *unit costs for conductor management; and*
- *the advanced metering business case.*[121]

Table 6.17: Draft decision distribution asset replacement and renewal capital expenditure ($ million real, June 2017)

Distribution asset replacement and renewal capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Western Power AA4 proposal	230.6	213.8	210.1	199.5	203.8	1,058.0
Conductor management	(1.5)	(1.5)	(1.7)	(1.9)	(2.2)	(8.7)
Metering	(4.6)	(5.9)	(6.9)	(7.1)	(7.1)	(31.6)
Draft decision	**224.7**	**206.4**	**201.5**	**190.5**	**194.6**	**1,017.7**

Source: Table 59, ERA draft decision.

[121] Paragraph 447, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

566. We have reviewed the ERA's reasoning for these amendments, along with the advice provided in the ERA's technical consultant's report (the GHD report), and submit the following response to the ERA's distribution asset replacement capex draft decision (see Table 6.18).

Table 6.18: Revised AA4 proposal on distribution asset replacement and renewal capital expenditure ($ million real, June 2017)

Distribution capex amendments	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Conductor management (unit rate adjustment)	218.7	210.0	210.0	Western Power accepts this amendment
Metering (net of capital contributions)	123.0	91.4[122]	116.4	Western Power accepts this amendment in principle, however the required expenditure has been revised to reflect metering replacement volumes proposed by GHD

567. These distribution capex amendments are discussed in the following sections.

6.3.3.1 Conductor management unit rates

568. Though the ERA accepts the conductor replacement volumes, it requires a unit rate adjustment from $100,000 per kilometre to $96,000 per kilometre. This reduction is based on advice provided by GHD.

569. GHD formed this advice based on the unit rate included in Western Power's Distribution Overhead Corridor Business Case for the 2017/18 financial year. The $96,000 per kilometre average rate in that business case was based on the mix of work planned to be undertaken in that year.

570. Unit rates for replacement of overhead conductor may vary between business cases and financial years depending on the mix of projects being completed. Conductor replacement unit rates depend on:

- the configuration and complexity of the conductor installation that is being replaced (e.g. three phase vs single phase, low voltage vs high voltage)
- the location of the works, which impacts costs (e.g. metro vs country differ in mobilisation and traffic management costs)

571. The mix of conductors and their location, are determined annually with an objective of maximising risk reduction for the investment. Recognising the variable nature of unit rates, we accept the $96,000 per kilometre estimate and have reduced the expenditure forecast to $210 million accordingly.

6.3.3.2 Metering

572. The AA4 proposal was based on Western Power installing 355,493 new and replacement meters at a cost of $137.3 million (excluding the communication and IT costs associated with the Advanced Metering Infrastructure (AMI) program). The ERA *considers installing modern electronic devices with enhanced capabilities in new properties and when replacing old meters is consistent with good electricity industry practice and, therefore, is consistent with the new facilities investment test.*[123]

[122] Note the ERA advised in footnote 50 of its draft decision that this number will be increased by approximately $25 million in the final decision due to the ERA accepting GHD's revised metering volumes forecast. This results in a revised capex forecast of $130.8 million.

[123] Paragraph 451, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

573. In its draft decision, the ERA adjusts the forecast number of meter replacements to 273,493. This adjustment was made for consistency with the number of new meters included in Western Power's demand forecast and a reasonable forecast of non-compliant meters requiring replacement during the AA4 period. This change to metering volumes reduces Western Power's forecast capital expenditure by $31.6 million to $105.7 million.

574. However, subsequent advice from GHD led the ERA to amend its forecast metering volumes to 331,925. [124]The ERA advises it had insufficient time to include the amended forecast in the draft decision, instead noting that the revised capital expenditure forecast would increase by around $25 million and that this adjustment would be made in its final decision.

575. The $25 million upward adjustment takes the forecast metering replacement expenditure to $130.7 million, consistent with the ERA's adjustment, which we consider is reasonably expected to meet the requirement of the NFIT. We have therefore accepted the ERA's revised forecast and have amended the AA4 forecast RAB accordingly.

6.3.4 Forecast distribution asset replacement and renewal capital expenditure

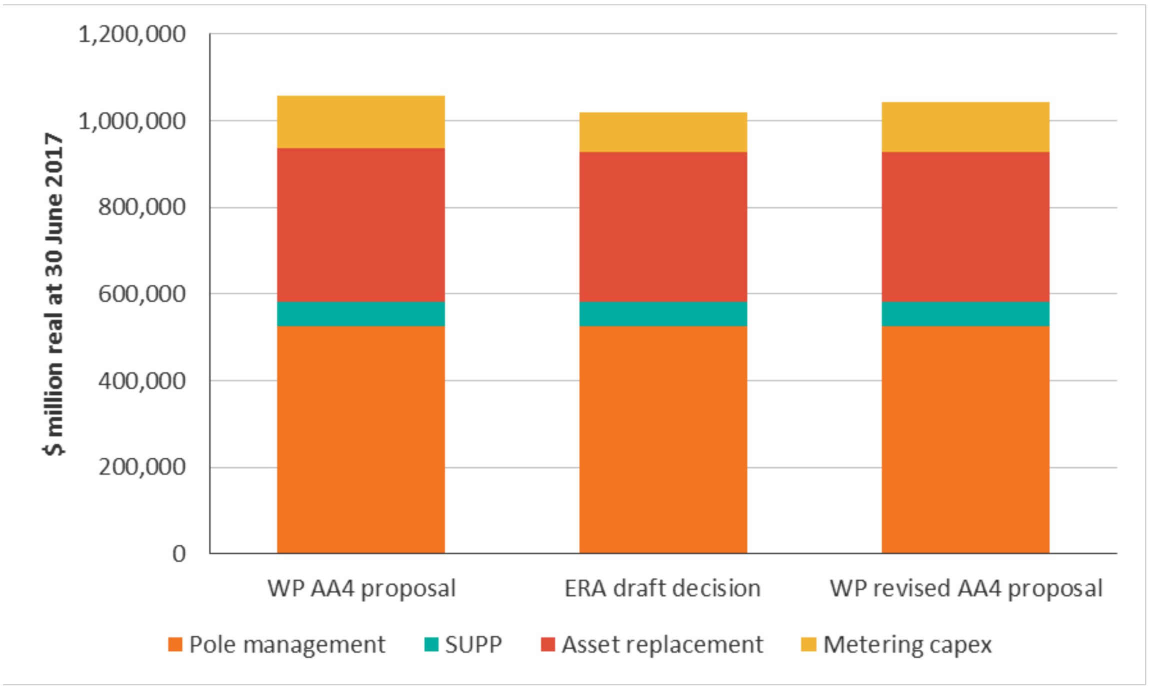
576. Taking into consideration the ERA's draft decision and the resulting adjustments to forecast capital expenditure, the revised AA4 forecast distribution asset replacement and renewal capital expenditure is presented in the following table.

Table 6.19: Revised AA4 proposal on distribution asset replacement and renewal capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Distribution asset replacement and renewal capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Cable management	1.5	1.5	1.5	1.5	1.5	7.6
Conductor management	35.8	34.7	41.5	46.2	51.8	210.0
Protective device management	2.5	3.9	3.7	3.8	5.6	19.4
Streetlight management	3.9	3.9	3.9	3.9	3.9	19.4
Switchgear management	3.9	3.8	3.8	3.8	3.8	18.9
Transformer management	9.5	9.9	9.6	9.7	9.6	48.3
Other replacement	2.8	5.7	4.9	3.0	4.0	20.5
Total asset replacement	**59.9**	**63.3**	**68.8**	**71.8**	**80.2**	**344.1**
Metering	14.4	22.2	26.9	26.5	26.5	116.4
Pole management	137.2	106.6	99.8	94.8	86.5	525.0
SUPP	15.0	19.5	12.8	3.2	6.8	57.2
Total asset renewal and replacement	**226.5**	**211.6**	**208.2**	**196.2**	**200.1**	**1,042.6**

[124] Footnote 50, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Figure 6.11: Comparison of distribution asset replacement and renewal direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.3.5 Distribution improvement in service

577. In the AA4 proposal, Western Power forecasted $94 million of distribution improvement in service capex is required during the AA4 period. This comprised $19.2 million for reliability-driven investment and $74.8 million for investment in SCADA and communications.

578. The reliability-driven expenditure forecast includes $8 million for the Kalbarri microgrid, which has been included in the AA4 forecast RAB by the ERA. However, the ERA excludes the remaining $11.2 million of reliability-driven expenditure on the basis that:

> *the remaining expenditure is not supported by demonstrated benefits. Consequently the ERA considers the expenditure is not reasonably likely to meet the new facilities investment test and must be removed.* [125]

579. The ERA also excludes $25.1 million of SCADA and communications capex related to installing the communications backbone for the AMI program. While the ERA gives in-principle support to the installation of modern electronic devices with enhanced capabilities, it considers further information is required to demonstrate the communications component of AMI meets the requirements of the NFIT.

580. The ERA's reductions to distribution improvement in service capex included in the AA4 forecast RAB is presented in Table 6.20.

[125] Paragraph 462, ibid.

Table 6.20: Draft decision distribution improvement in service capital expenditure ($ million real, June 2017)

Distribution improvement in service capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Western Power AA4 proposal	23.0	29.0	16.0`	13.8	12.2	94.0
Distribution reliability other	-	(2.7)	(1.5)	(0.5)	(0.5)	(5.1)
Targeted reliability-driven automation	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	(5.6)
RD pilot projects	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.5)
Corporate – advanced meters (AMI)	(10.5)	(10.5)	(1.6)	(1.7)	(1.0)	(25.1)
Draft decision	**11.4**	**14.7**	**11.7**	**10.4**	**9.5**	**57.7**

Source: Table 61, ERA draft decision.

581. We have reviewed the ERA's reasoning for these amendments, along with the advice provided in the ERA's technical consultant's report (the GHD report), and submit the following response to the ERA's distribution improvement in service draft decision (see Table 6.21).

Table 6.21: Revised AA4 proposal on distribution improvement in service capital expenditure ($ million real, June 2017)

Distribution capex amendments	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Distribution reliability other	13.1	8.0	11.9	Western Power has not made this amendment, and submits further information to support inclusion of a revised amount of capex in the AA4 forecast RAB
Targeted reliability-driven automation	5.6	0.0	0.0	Western Power accepts this amendment
RD pilot projects	0.5	0.0	0.0	Western Power accepts this amendment
Corporate – advanced meters (AMI)	25.1	0.0	27.1	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB

582. These distribution capex amendments are discussed in the following sections.

6.3.5.1 Distribution reliability other

583. The ERA includes $8 million in the AA4 forecast RAB for the Kalbarri microgrid project and Western Power will continue to progress this vital edge-of-grid reliability project over the course of the AA4 period.

584. The revised distribution reliability expenditure reflects Western Power's proposed investment in projects that, in a similar vein to the Kalbarri microgrid, target edge-of-grid reliability issues, or can efficiently improve the customer experience for incremental expenditure. These projects will focus on:

- utilising new technology such as automation and control methods with algorithms, to detect issues, remotely isolate faults, and restore supply quickly. We are looking at the feasibility of using existing meshed network and assets in urban areas to create islanded networks and utilise existing generation for continuity of supply in edge-of-grid areas
- providing additional operational flexibility to maintenance crews by enabling the connection of generators to the network (especially in country areas) to decrease the severity of long planned and unplanned outages.

585. These projects are not expected to deliver a significant benefit to overall network reliability averages, and therefore we propose no adjustment to system average interruption duration index (SAIDI) or system average interruption frequency index (SAIFI) targets as a direct result of these investments. Rather, the additional $3.9 million of 'reliability driven other' expenditure is designed to improve the customer experience by improving Western Power's ability to address and isolate faults.

586. As these projects are further refined, they will pass through Western Power's staged investment governance process, which includes detailed business case development and evaluation against the NFIT.

6.3.5.2 Targeted reliability-driven automation and RD pilot projects

587. Western Power has reviewed its forecast distribution capex program, and accepts these projects will not be delivered during the AA4 period. No new facilities investment has been added to the AA4 forecast RAB.

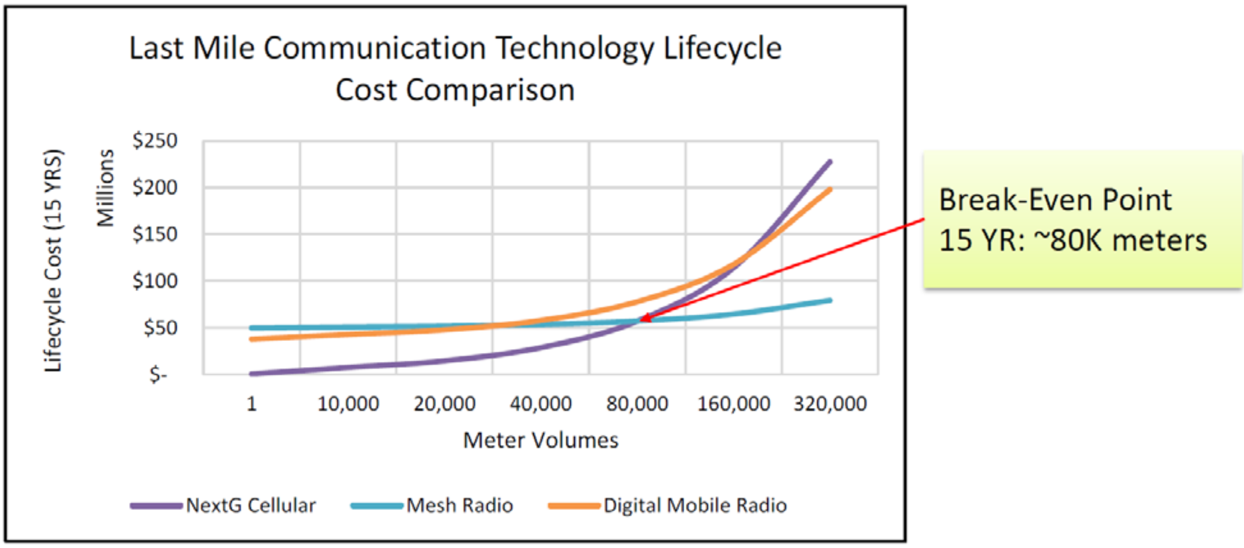
6.3.5.3 Advanced metering infrastructure – SCADA and communications

588. The AA4 proposal included $25.1 million of forecast investment in SCADA and communications systems associated with the installation of advanced metering infrastructure (AMI). The AMI-related SCADA and communications investment is required to install a radio frequency (RF) mesh two-way communications network, leveraging Western Power's existing fibre backbone where possible.

589. The RF mesh network is the communications backbone of the AMI program and is the element that enables data transfer between the meters installed at customers' premises and the IT systems controlled by Western Power. The RF mesh network was used in Western Power's Perth Solar Cities smart meter trial and is proven technology.

590. Options analysis for the communications backbone shows that RF mesh is the most efficient cost option for the volume of advanced meters being installed by Western Power.

Figure 6.12: Options analysis for the AMI communications backbone



591. The proposal to construct the RF mesh network and leverage existing fibre where possible also has the advantage that the communications network will act as a platform for both AMI and distribution automation. Western Power's current distribution automation communications infrastructure is coming to the end of its useful life and will need to be replaced incrementally over the next decade. Therefore the AA4 period is the ideal and most efficient window for replacing this critical infrastructure with a solution that can also support AMI.

592. In its draft decision, the ERA considers the forecast capital expenditure to install advanced meters meets the requirement of NFIT, stating:

> *The ERA considers installing modern electronic devices with enhanced capabilities in new properties and when replacing old meters is consistent with good electricity industry practice and, therefore, is consistent with the new facilities investment test.*[126]

593. Consistent with this view, the ERA includes capex in the AA4 forecast RAB commensurate with Western Power installing 273,493 advanced meters, with a view to revising provisions upwards to 331,925 meters in its final decision.[127] It appears there is general alignment between Western Power, GHD and the ERA on the prudence of installing advanced meters.

594. However, the ERA excludes capex associated with the installation of the communications and IT infrastructure necessary to facilitate advanced metering. This includes the $25.1 million proposed for the RF mesh system.

595. The ERA considers Western Power has not been able to demonstrate that the expenditure on the communications and IT components of AMI is reasonably expected to satisfy the requirements of the NFIT. The ERA states that *inconsistencies in data across the information provided by Western Power on its advanced metering business case made analysis difficult*.[128]

126 Paragraph 451, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
127 Footnote 50, ibid.
128 Paragraph 454, ibid.

596. We accept that there were some inconsistencies in the data provided to the ERA and GHD due to the business case and Board approval process being prepared for a different time period than the five-year AA4 proposal.

597. The AMI business case was produced in December 2016 and provided a three-year[129] view of the AMI expenditure and benefits. The business case was initially shared with the ERA in February 2017, before being provided to the ERA in October 2017 as part of Western Power's AA4 proposal. The business case was supported by a cost benefit analysis model, which was provided to GHD on 22 November 2017.

598. The AA4 proposal however, provides a five-year view of expenditure for the purpose of determining the AA4 forecast RAB (and subsequent revenue requirement). The AA4 proposal therefore reflects a further two years of advanced metering deployment. In addition, the presentation of expenditure in the business case is in nominal dollars and includes an allocation of indirect costs. The AA4 proposal is presented in real 2016/17 dollars and excludes indirect costs.

599. We accept that the differences in information provided to the ERA and GHD made it difficult to make an accurate NFIT assessment. During the time since the AMI business case was submitted to the ERA as part of the AA4 proposal, we have continued to refine and challenge the AMI capex proposal.

600. In February 2018, Western Power presented a change control for the AMI business case to its Board of Directors. The change control includes updated expenditure and updated benefits, and is supported by an updated cost-benefit analysis. This updated information has been provided to the ERA as a confidential attachment[130] to this response to the draft decision.

601. The change control updates AMI costs to reflect the five-year view of expenditure, and incorporates revised costs following a competitive tender process for meters, the RF mesh network and the IT system requirements. Based on the change control, AMI expenditure forecast in this revised AA4 proposal adjusts the SCADA and communications (RF mesh network) costs from $25.1 million to $ 27.1 million.

602. Western Power considers the AMI program to be one of the most important programs of work to be delivered during AA4. Feedback from our customer engagement program indicated that customers support adaptation of new technology and would support adoption of advanced meters where it is efficient to do so. Advanced meters are now routinely deployed by utilities around the world, and research indicates that the benefits across the electricity value chain outweigh the costs of deployment over the meter's life.

603. The IT and communications infrastructure are essential components of the AMI program if customers are to realise the full benefits. Without the installation of these components the advanced meters installed by Western Power will not be advanced. The ERA's technical adviser GHD notes:

> *A key aspect of SCADA and communications investment is in 'last mile telecommunications', which allows automation and remote control, and data capture from across the distribution network. Improved last mile communications are critical for the implementation of advanced metering and the efficient connection and management of emerging technologies such as microgrids and battery storage systems. The use of advanced meters will be a significant enabling technology for a range of Demand Management /Non-network initiatives in the future.*[131]

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129 A three-year view was developed as the original AMI business case was developed and approved on the understanding that Western Power would be moving to the AER's regulatory framework, which required a three-year forecast for Western Power's first regulatory cycle. The move to the AER framework did not proceed.

130 Given the confidential nature of the NPV assessment and cost benefit analysis, this information has been provided to the ERA directly and is not suitable for publication on the ERA's website.

131 Page 110, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

604. We are committed to delivering the AMI program during the AA4 period and have progressed to selecting preferred suppliers for both the advanced meters and the provision of hardware and software for establishment of radio mesh communication infrastructure. Delivered in full, AMI will enable safer and more efficient metering services, timely and reliable data to enhance the customer experience, improve understanding of end user behaviours to facilitate external and internal new business opportunities that utilise the grid and assist to reduce the cost of asset management.

605. Western Power's revised AMI capex proposal is presented in Table 6.22.

Table 6.22: Revised AA4 proposal on AMI capital expenditure ($ million real, June 2017)

AMI capex components	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Metering (gross capex)	137.3	105.7[132]	130.7	Western Power has revised its metering forecast to reflect metering replacement volumes proposed by GHD
Capital contributions	14.3	14.3	14.3	
Metering (net of capital contributions)	123.0	91.4[132]	116.4	
Metering volumes	335,493	273,493[133]	331,925	Western Power has revised its metering forecast to reflect metering replacement volumes proposed by GHD
SCADA and communications (AMI RF mesh communications network)	25.1	-	27.1	Western has revised its AMI-related communications forecast to reflect the February 2018 AMI change control, and submits further information to demonstrate this expenditure is reasonably expected to satisfy the NFIT.
IT (AMI IT systems – HUB, Silver Spring UIQ and AM deployment tool))	15.0	-	34.4	Western has revised its AMI-related IT forecast to reflect the February 2018 AMI change control, and submits further information to demonstrate this expenditure is reasonably expected to satisfy the NFIT.
Total AMI (gross capex)	**177.4**	**105.7**	**192.3**	
Total AMI (net of capital contributions)	**163.1**	**91.4**	**178.0**	

606. As shown in the above table, we have accepted the ERA's revised metering forecast. This is discussed in section 6.3.3.2.

607. As the AMI-related IT costs are allocated to the corporate capex regulatory category, therefore revised IT costs are discussed in section 6.4.2.

608. The variation to the AMI SCADA and communications forecast is $2.0 million. This cost estimate increase is a result of the detailed design and competitive tendering process undertaken in 2017, which has refined the actual cost of the RF mesh network.

132 Note the ERA advised in footnote 50 of its draft decision that this number will be increased by approximately $25 million in the final decision due to the ERA accepting GHD's revised metering volumes forecast. This results in a revised capex forecast of $130.8 million.

133 As per footnote 50, the ERA advises its intent to revise the metering volume to 331,925 in its final decision.

609. We submit that the revised $27.1 million capex forecast for the RF mesh solution is a critical part of the overall AMI solution and is fundamental to the AMI program delivering the proposed benefits and a positive net present value (NPV).

610. The benefits we expect the AMI program will deliver are discussed in the following section.

6.3.5.4 Benefits of AMI

611. In its draft decision, the ERA disallowed the AMI IT and communications forecast capex as it considered the benefits presented in the initial business case and cost benefit analysis model were overstated and difficult to analyse.

612. The ERA states:

> *After reviewing the material provided by Western Power and taking account of advice from GHD, the ERA considers the benefits have been overstated and the net present value is actually negative* [134]

613. And:

> *As Western Power has not been able to demonstrate a positive net benefit, the proposed expenditure on the communication infrastructure is not reasonably likely to meet the requirements of the new facilities investment test.*[135]

614. In our review of the AMI business case and change control process, we have revisited the cost benefit analysis to correct for updated costings, inconsistencies in presentation, inflation, discount rates and cost allocations.

615. The revised cost benefit analysis, along with a detailed explanation of the changes between the original business case and the change control has been provided in Attachment 6.2.[136] We have also provided information that demonstrates the positive NPV associated with each of the AMI benefits, and sensitivity analysis that shows how the overall NPV for AMI is positive, even when conservative estimates are adopted.

616. We therefore submit that the $27.1 million proposed for the RF mesh communications network (along with the $34.4 million AMI-related IT costs) are reasonably expected to satisfy the requirements of the NFIT and should be included in the AA4 forecast RAB.

617. In paragraph 457 of its draft decision, the ERA also raises concerns about the following benefits, which it considers (based on the information provided provide to-date) are overstated:

> *Specific benefits identified as being overstated are:*
>
> - *the level of savings from deferred network investment and power correction factors attributable to advanced metering data;*
> - *the timing of savings from service connection monitoring as these require the communications to be operational so should only be taken into account from the date it is assumed the data becomes available;*

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134 Paragraph 456, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

135 Paragraph 458, ibid.

136 Given the confidential nature of the NPV assessment and cost benefit analysis, this information has been provided to the ERA directly and is not suitable for publication on the ERA's website.

- *the reductions in call centre costs and voltage balancing are high compared with data from advanced metering rollouts conducted elsewhere; and*
- *a benefit from avoided communication system costs for unregulated services should not have been included as a benefit to be covered by regulated investment.*[137]

618. All of these benefits (whether overstated or not) are directly related to the communications and IT components of AMI, and therefore would not be realised if the IT and communications components are not delivered.

619. We have considered each of the above points in turn, and have provided analysis on each of them at Attachment 6.2. A summary of our position is provided in the following sections.

6.3.5.4.1 The level of savings from deferred network investment and power correction factors attributable to advanced metering data

620. In its technical review, GHD considered the calculation for deferred peak demand reduction due to time-of-use (TOU) tariffs is reasonable compared with other examples. However, GHD queries Western Power's assumption of the TOU take up rate increasing from 25 per cent to 100 per cent by the end of the 15-year modelling period.

621. We would like to highlight that the 100 per cent take up rate is only assumed to occur during the final year of the 15-year modelling period. The model does not recognise any benefits from take-up of TOU tariffs until year five.

622. Western Power's updated cost benefit model adjusts downwards the benefits associated from a 100 per cent take-up of TOU and other related input assumptions by 50 per cent. This allows for the risk of less than 100 per cent take-up of TOU at the end of the 15-year modelling period.

623. This conservative estimate still results in a positive NPV.

624. We have also adjusted the power correction factor benefit downwards. This is due to a change in approach to calculating this benefit. The resulting benefit is more in line with GHD's view that it should be approximately one half of the amount estimated by Western Power in the original business case. Again, this adjustment still results in a positive NPV.

6.3.5.4.2 The timing of savings from service connection monitoring as these require the communications to be operational so should only be taken into account from the date it is assumed the data becomes available

625. GHD considers the benefits delivered from the ability of advance meters to monitor the condition of the overhead service connection should be deferred by three years, thereby reducing its assessment of Western Power's proposed benefits by 32 per cent.

626. We have updated the value of this benefit in the revised cost benefit analysis model to reflect adjustments to modelled volumes and capital being deferred rather than avoided.

627. We still consider AMI is the most efficient solution for a change in overhead service connection monitoring. The updated benefit value is based on avoided field operating expenditure and deferral of capex replacement as a result of the benefits delivered from remote monitoring of overhead service connections. The benefit calculation has been aligned to approximately one third of the overhead service connections monitoring program, which overlaps with the location of planned AMI deployed meters.

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[137] Paragraph 457, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

628. We have not attributed a financial benefit to the significant safety benefits of reducing the potential of electric shocks from AMI power quality monitoring.

6.3.5.4.3 The reductions in call centre costs and voltage balancing are high compared with data from advanced metering rollouts conducted elsewhere

629. GHD acknowledges a reduction in call centre costs is a benefit of an advanced meter program. However, it considers Western Power's assumed rate is higher than the levels assumed in other rollouts they reviewed from around the world (Ameren Illinois and BC Hydro).

630. We consider the assumptions underpinning our calculation of the call centre benefit are already conservative, because:

- our model caps the impact of advanced meters on call reductions at 30 per cent. This is conservative considering the increasing number of advanced meters to be deployed by the end of the 15-year modelling period. We note that in a June 2015 *Study on cost benefit analysis of Smart Metering Systems in EU Member States* by the Institute of Communication & Computer Systems of the National Technical University of Athens, several countries (including Belgium, Hungary and Germany) cited call centre savings of between 30 to 50 per cent
- the average number of incoming calls per year is kept constant and not adjusted upwards for any increase in customer numbers across the 15-year period.

631. From a model sensitivity perspective, if Western Power were to apply GHD's more conservative benefits assumption, noting that this number was derived from a 50 per cent reduction to Western Power's original business case estimate, the program would still result in a positive NPV.

632. GHD acknowledges that benefits associated with reducing technical losses have been included in advanced meter rollouts internationally, however, it considers Western Power's benefits assumption is too high.

633. We have updated the value of this benefit in the cost benefit analysis model to reflect a more conservative view of the following parameters:

- the original cost benefit analysis model used a starting level of technical losses of 4.3 per cent and compared this to an expected improved level of technical losses associated with advanced meters of 3.44 per cent. We have adjusted upwards the expected improved level of technical losses to 4.03 per cent to reflect more recent information. This reduces the assumed savings in losses from 20.7 per cent to 6.3 per cent. GHD's review considered a savings in losses of 13.5 per cent to be reasonable.
- we have also adjusted the calculation to apply the Short Term Energy Market (STEM) energy price of 0.06 $/kWh in place of the network price of 0.08 $/kWh.

634. After adjusting for the above factors, Western Power's adjusted benefit is lower than GHD's initial assessment but still result in a positive NPV.

6.3.5.4.4 A benefit from avoided communication system costs for unregulated services should not have been included as a benefit to be covered by regulated investment.

635. GHD considers benefits arising from unregulated revenue should not be included in the AMI business case. We agree with this view and accordingly have not included any benefits arising from potential unregulated revenue streams.

636. The benefits assumed by Western Power have been derived from the avoided costs associated with SCADA and communications equipment related to the covered network (approximately 57 per cent of the benefit)

and potential incremental regulated revenue to be derived from third party access to the communications infrastructure (approximately 43 per cent of the benefit).

6.3.5.4.5 Sensitivity analysis

637. In addition to undertaking a detailed internal sensitivity analysis on Western Power's estimated benefits, if Western Power were to apply GHD's more conservative assumptions the program would still be in a net positive position. Sensitivity analysis demonstrating this has also been provided to the ERA.

638. Western Power considers that the cost benefit analysis and related sensitivity analysis supporting the approved change control position, demonstrate a positive net benefit for the AMI program under all scenarios tested.

639. Accordingly, Western Power considers that the forecast expenditure on the AMI program, including the deployment of advanced meters and the associated IT and communications infrastructure, is reasonably expected to meet the requirements of the new facilities investment test and should therefore be included in the forecast capital base.

640. From a model sensitivity perspective, if Western Power were to apply GHD's more conservative assumptions the program would still be in a net positive position. Sensitivity analysis demonstrating this has also been provided at Attachment 6.2.

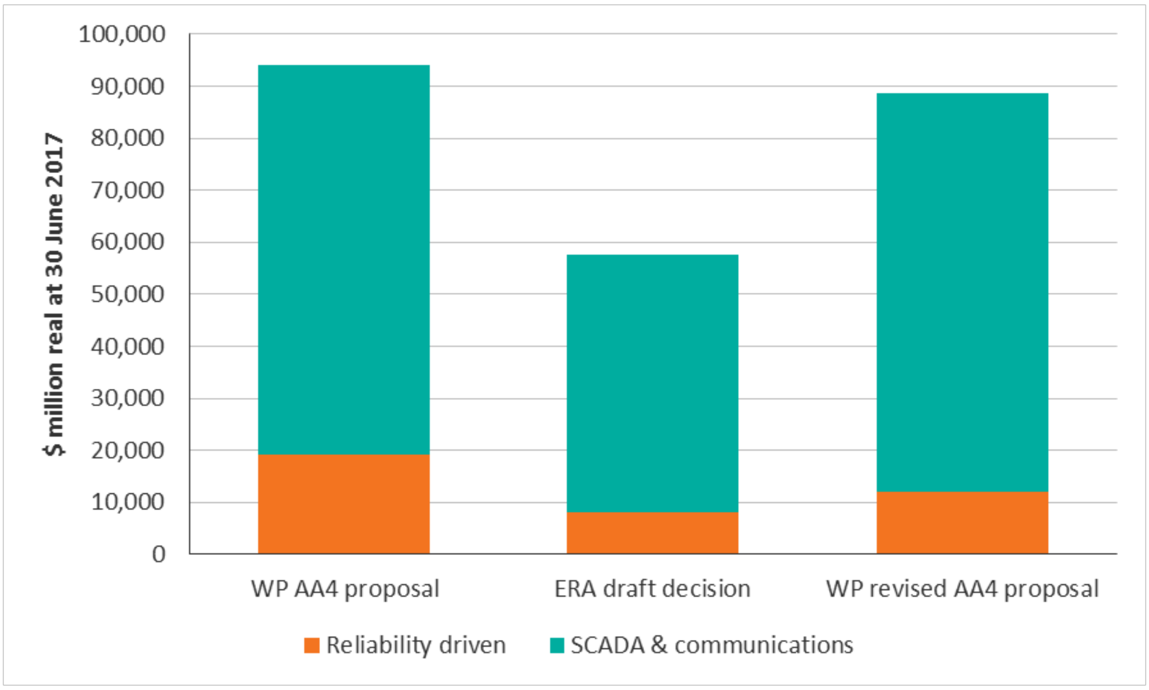
6.3.6 Forecast distribution improvement in service capital expenditure

641. Taking into consideration the ERA's draft decision and the resulting adjustments to forecast capital expenditure, the revised AA4 forecast distribution improvement in service capital expenditure is presented in the following table.

Table 6.23: Revised AA4 proposal on distribution improvement in service capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Distribution improvement in service capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Reliability other	2.7	7.8	0.8	0.5	0.1	11.9
Pilot projects	-	-	-	-	-	-
Reliability driven automation	-	-	-	-	-	-
Total reliability driven	**2.7**	**7.8**	**0.8**	**0.5**	**0.1**	**11.9**
Asset replacement	3.9	5.2	7.6	7.4	8.2	32.2
Core infrastructure growth	0.2	-	-	-	-	0.2
Corporate	7.8	12.2	4.5	1.7	1.0	27.1
Master station and operating systems	4.2	4.5	4.1	3.0	1.3	17.2
Total SCADA & communications	**16.1**	**21.9**	**16.2**	**12.1**	**10.5**	**76.8**
Total improvement in service	**18.8**	**29.7**	**17.0**	**12.5**	**10.6**	**88.8**

Figure 6.13: Comparison of distribution improvement in service direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.3.7 Distribution compliance

642. In its draft decision, the ERA makes no adjustment to forecast distribution compliance capex, stating:

> *Western Power's proposed compliance program is significantly lower than actual expenditure in AA3 reflecting the adoption of its risk-based management approach. Based on the information provided by Western Power and advice from GHD, the ERA is satisfied the proposed expenditure is reasonably likely to meet the requirements of the new facilities investment test.*[138]

643. We therefore submit the same level of distribution compliance new facilities investment as put forward in the AA4 proposal.

6.3.8 Forecast distribution compliance capital expenditure

644. As per the ERA's draft decision, the forecast distribution compliance capex for the AA4 period remains unchanged from the AA4 proposal

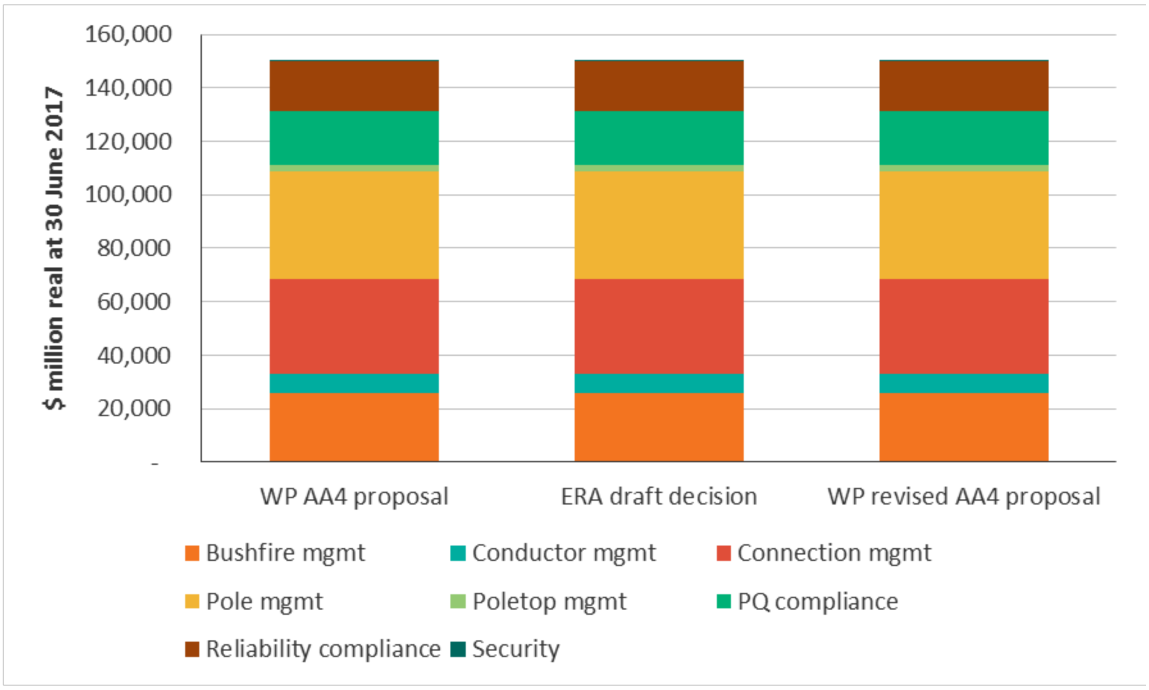
Table 6.24: Revised AA4 proposal on distribution compliance capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Distribution compliance capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Bushfire management	2.4	9.1	9.1	2.6	2.6	25.9
Conductor management	1.4	1.4	1.4	1.4	1.4	7.0
Connection management	7.6	7.1	7.1	7.1	6.6	35.4
Pole management	2.8	9.5	9.4	9.3	9.5	40.5

[138] Paragraph 469 ibid.

Distribution compliance capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Poletop management	0.1	0.4	0.6	0.4	0.8	2.3
PQ compliance	4.1	4.1	4.1	4.1	4.1	20.3
Reliability compliance	4.4	4.4	3.5	3.0	3.0	18.3
Security	0.1	0.1	0.1	0.1	0.1	0.5
Total compliance	**22.9**	**36.1**	**35.3**	**28.0**	**28.1**	**150.3**

Figure 6.14: Comparison of distribution compliance direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.4 Corporate capital expenditure

645. In its draft decision, the ERA excludes $116.1 million of forecast capital expenditure from the calculation of AA4 target revenue. The ERA's draft decision:

- removes fleet assets from the RAB
- removes advanced metering expenditure
- removes expenditure for the new customer relationship management (CRM) software.

Table 6.25 shows the ERA's amendments to forecast corporate capex.

Table 6.25: Draft decision corporate direct cost capital expenditure ($ million real, June 2017)

Corporate capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Western Power AA4 proposal	84.4	101.5	190.8	51.6	58.7	487.1
Fleet adjustment	(11.8)	(6.1)	(26.9)	(7.6)	(24.7)	(77.2)
Advanced metering infrastructure	(10.0)	(2.0)	(0.9)	(0.9)	(1.2)	(15.0)

Corporate capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
CRM software	(4.8)	(4.8)	(4.8)	(4.8)	(4.8)	(24.0)
Draft decision	**57.8**	**88.6**	**158.3**	**38.3**	**28.0**	**370.9**

Source: Table 66, ERA draft decision.

646. The ERA also requires Western Power to submit more evidence to demonstrate that its proposed corporate capital expenditure is reasonably expected to meet the NFIT.

647. We have reviewed the ERA's reasoning for these amendments, along with the advice provided in the ERA's technical consultant's report (the GHD report), and submit the following response to the ERA's corporate capex draft decision (see Table 6.26).

Table 6.26: Revised AA4 proposal on corporate direct cost capital expenditure ($ million real, June 2017)

Corporate capex amendment	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Fleet adjustment	77.2	0.0	0.0	Western Power accepts this amendment
Advanced metering infrastructure	15.0	0.0	34.4	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB
CRM software	24.0	0.0	24.0	Western Power has not made this amendment, and submits further information to support inclusion of this capex in the AA4 forecast RAB

648. These items and other aspects of the corporate capital expenditure forecast for the AA4 period are discussed in the following sections.

6.4.1 Fleet adjustment

649. In the AA4 proposal, we submitted that fleet assets should be added to the RAB. This is the result of a forthcoming change in accounting standards requiring operating leases to be recognised as an asset (and the future payments as a liability).

650. The ERA considers Western Power should maintain the current arrangements for fleet, as unregulated assets, and fleet expenditure should not be added to the RAB. The ERA also adjusts Western Power's forecast AA4 operating expenditure to remove the step change reduction in indirect costs associated with the change in treatment of fleet costs.

651. We accept this amendment and have removed $77 million of fleet expenditure from the AA4 forecast RAB.

6.4.2 Advanced metering infrastructure – IT costs

652. In the AA4 proposal, Western Power submitted it will invest $15 million in IT costs relating to the installation of advanced metering infrastructure (AMI).

653. As discussed in section 6.3.5.3, in its draft decision the ERA considers the forecast capital expenditure to install advanced meters is reasonably expected to meet the requirements of the NFIT. However, it

considers the benefits associated with the IT and communications elements of the AMI program have been overstated and a positive NPV has not been demonstrated.

654. We have conducted further analysis of the AMI program, in particular the IT requirements and associated benefits. A Change Control has been provided to the ERA, together with an explanation of the variances between the original December 2016 business case, the AA4 proposal and the change control position.

655. The AMI-related IT expenditure is required to deliver upgrades to three key IT systems that are necessary to enable Western Power to store, analyse and use the data collected from advanced meters and provide advanced metering services. These key IT systems are:

- Network Management System (NMS) – this is the head-end system that communicates with the installed meters, capturing and storing metering data for interpretation and analysis
- the advanced meter deployment tool, which is the interface that enables deployment and field servicing of the 331,925 advanced meters being installed
- upgrades to the Metering Business System (MBS) which will enable advanced metering data to be processed for customer billing,

656. The IT upgrades to MBS, NMS and the advanced meter deployment tool are critical to the AMI program and are a prerequisite for the program delivering the expected benefits to customers and Western Power.

657. Western Power undertook a detailed design and competitive tender process during 2017. This led to an increase in forecast IT expenditure from $15.0 million to $34.4 million. This increase also reflects a scope increase to include a route optimisation tool which will support the ongoing optimisation of meter reading routes to enable better management of metering deployment costs.

658. Tenderers were required to provide a schedule of rates for unit prices with pricing options for volume discounts, licensing options and maintenance fees. The NMS models were assessed for each tender response including consideration of Software as a Service (Saas), licensed on premise and managed services. Scope options were also assessed to determine which party was best placed to deliver the design work, integration and maintenance services.

659. A preferred vendor has now been selected to provide the NMS and the communications devices.

660. We note that in its technical review, GHD highlighted a concern that the results of its benchmarking indicated Western Power's estimated costs in the business case may be too low.[139] We consider the revised forecasts appropriately reflect current market prices.

661. As described in section 6.3.5.3, we have undertaken a revised NPV assessment of the benefits associated with the AMI IT system to account for new assumptions and the costs supporting the approved Change Control position. Our analysis, as provided to at Attachment 6.2, demonstrates a positive NPV across the suite of benefits delivered from the installation of the AMI IT and communication systems.

662. Therefore we submit that the revised AMI IT forecast of $34.4 million is reasonably expected to satisfy the requirements of the NFIT and should be included in the AA4 forecast RAB.

[139] Page 112, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

6.4.3 CRM software

663. The AA4 proposal included $24 million of forecast capex to implement a new CRM system.

664. As described by GHD in its technical review, *the investment in a revised CRM system is driven by two key factors:*

- *the need to replace the existing system that is over 10 years old*
- *a desire for better enable customer engagement*[140]

665. GHD advised it accepts there is a need for investment in some sort of CRM solution, stating:

> *The aim of the new system is to create an integrated system that covers a disparate number of elements including customer quotations, fault reporting, metering, and vegetation management and work orders. From our review of this forecast expenditure, we accept that there is a requirement for a new and comprehensive system.*[141]

666. GHD recommended the ERA accepts Western Power's proposed CRM expenditure in the AA4 forecast RAB however, GHD also recommended that Western Power should re-asses the planned expenditure level:

> *…following our internal discussions with our IT specialists, including staff with extensive experience in CRM systems, we believe the forecast CAPEX allowance for a new CRM system is excessive. We are of the opinion there are a number of different potential solutions that could work well for Western Power, including a number of Software as a Service (SaaS) products that could materially reduce the CAPEX required to implement a new CRM.*[142]

667. Western Power notes there is general agreement that a level of investment to upgrade Western Power's capabilities is required. Further information is provided in this response as evidence the CRM solution we propose represents an efficient amount of expenditure and is an appropriate product.

6.4.3.1 CRM expenditure

668. The AA4 proposal stated Western Power will invest $24 million to implement a new customer management system. For simplicity, the entire $24 million was denoted as CRM expenditure. However, the $24 million covers expenditure on the CRM system itself and associated systems that will leverage the CRM platform and help to enhance the quality of customer service.

669. The CRM package of work will deliver an integrated customer management system including customer relationship records, customer communication preferences including the capability to send mass and tailored communications, customer data integration between disparate systems, a self-service portal, workflow management and the access solutions and queueing process in accordance with the Applications and Queuing Policy and Contributions Policy.

670. Table 6.27 shows a breakdown of the $24 million forecast costs.

140 Page 178, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.
141 Ibid.
142 Ibid.

Table 6.27: Breakdown of proposed $24 million CRM capital expenditure ($ million real, June 2017)

Customer service and engagement component	Detail – Functional	Cost	Total cost
CRM system	CRM core	5.1	16.0
	Customer service improvements	4.3	
	Access solutions and queuing process (to replace SalesForce)	1.5	
	Customer data warehouse, data model and GIS	5.1	
Customer management components of Customer funded work process (DQM)			3.8
Customer data analytics			2.0
Metering data portal			1.9
Total			**23.7**

671. As shown in the table above, the cost of the CRM aspect of the solution is $16 million, and comprises the following elements:

- CRM core:
  - introducing new customer service capabilities that are not available in the current NetCIS
  - consolidating access to customer information through the new system
  - retiring NetCIS, which is essentially a network billing system with a customer database – it is not a CRM system.
- customer service improvements:
  - automating customer processes
  - introducing two way digital communication with customers
  - improving online and self-service access for customers
  - improving access to planned and unplanned outage information
  - increasing the frequency and accuracy information during outages.
- access solutions and queuing process:
  - replacing the SalesForce system, which is currently used to manage large or complex distribution requests, transmission load connections and generation applications in excess of 30 kVA, in accordance with the Applications and Queuing Policy and Contributions policy.
- customer warehouse, data model and GIS:
  - creating a single customer profile and ensuring relevant Western Power staff have access to this data to service customers
  - ensuring the customer profile includes all customer-related data, including preferences collected in the field, view from faults and other asset management activities
  - making data available on corporate GIS and ensuring customer and property information is easily accessible by Western Power field and operational staff, rather than solely office staff.

672. Implementing the CRM will also enable Western Power to upgrade the external customer funded design and construction process currently supported by the Distribution Quotation Management system (DQM). This system is more than 20 years old. The customer information and engagement capabilities within DQM

do not enable sufficient information history to be stored and effectively utilised on customer funded works for customers, electricians, consultants and developers. The CRM interface will provide an online platform for customers to initiate work and facilitate automatic updates to dramatically improve the visibility for the customer of their customer funded project.

673. A key benefit of the contemporary CRM system will be the enhanced customer data analytics available to Western Power from having access to a full suite of customer information. Using performance analytics will not only improve the customer experience but will provide insights to Western Power to inform future programs of work. In addition, capturing and analysing customer data collected through satisfaction surveys will further improve customer service.

674. The CRM system will also facilitate the development of a metering data portal which will provide online access to customers' interval reading data from advanced meters.

675. Delivering the entire package of CRM and associated system upgrades as proposed will allow Western Power to reduce the number of bespoke solutions required for the existing disparate systems to interface with each other. In addition, the proposed solution facilitates the following existing systems being retired:

- Oracle CC&B (NetCIS)
- DQM
- SalesForce
- Consultation Manager
- the Western Power Outage App.

676. Retiring these systems results in direct capital expenditure savings over the AA4 period, as the forecast expenditure on IT systems does not include the costs that would be required to upgrade, maintain and support these systems over AA4 and subsequent periods.

677. To validate the forecast expenditure on CRM and ensure it was in line with market costs, Western Power undertook a competitive market process, which concluded in April 2018. An expression of interest was issued to the top five system vendors. Three vendors provided compliant tender responses and these were subject to a technical capability evaluation and 'best and final offer' process.

678. From the tenders submitted, we selected the solution which best met our business and customer needs and was the least-cost solution compared to the other systems evaluated.

679. The CRM implementation is currently at the design and plan phase, with the full contract for implementation to be negotiated once the final requirements are detailed. There will be further opportunity to go back to market prior to commencing implementation, to refine costs and ensure value for money.

680. The CRM project will follow Western Power's normal governance frameworks. CRM implementation is scheduled to commence in January 2019.

681. We consider this proposed $16 million investment in a CRM solution is comparable with other distribution network business.

6.4.3.2 Appropriateness of the CRM product

682. With regard to GHD's statement:

> *We are of the opinion there are a number of different potential solutions that could work well for Western Power, including a number of Software as a Service (SaaS) products that could materially reduce the CAPEX required to implement a new CRM.*[143]

683. We can confirm that the CRM solution we propose is based on a Software as a Service implementation approach, and that SaaS products have been selected through the tender process. Where possible, off-the-shelf products are being applied and modified rather than developing a bespoke CRM solution from scratch.

684. The total CRM solution costs factor in efficiencies from adopting SaaS and therefore reflect a reasonable level of expenditure for a customer service system of this type. The majority of capital costs are associated with system configuration and design, integration, and data migration. Software licensing is not a major component.

685. We therefore submit that the proposed CRM solution and products are appropriate and represent efficient expenditure.

6.4.4 IT program delivery

686. Western Power has successfully delivered a substantial ICT portfolio during the AA3 period. The magnitude of this portfolio increased through the latter years of the AA3 period and into AA4. Wester Power is well-positioned to deliver the ICT investment described in this document because:

- Western Power groups ICT projects into programs of work based on the projects' objectives, and each program is supported by a dedicated program management team
- Western Power has undertaken a competitive procurement process to establish a panel of service providers, with the ability to rapidly scale and deliver efficiencies
- Western Power has undertaken a competitive process to select a lead systems integrator to assist in the management and delivery of strategic initiatives
- Western Power uses commercial contract mechanisms in its engagement of service providers to share and mitigate project delivery risk
- Western Power has adopted an agile project delivery approach for business improvement initiatives, which aids successful delivery through multiple progressive releases, ensuring value is achieved early but enabling the project team to control the scope
- Western Power's ICT function adheres to the broader investment governance and project delivery framework.

687. We therefore submit that Western Power has the capacity and capability to deliver all the ICT programs proposed for the AA4 period in full.

143 Ibid.

6.4.5 Depot modernisation

688. In the AA4 proposal, we forecast $184 million investment in the [redacted] Depot Modernisation Program[redacted]. As the ERA states:

> *The expenditure is supported by business cases which GHD advises are reasonable.*[144]

689. However, the ERA requests evidence that Western Power is reasonably certain the depot modernisation project will proceed during the AA4 period, and that the savings arising from modernised depots have been incorporated in forecast operating and capital expenditure.

690. [redacted] The program is a key component of Western Powers' Property Management Strategy.

691. [redacted] Western Power will redevelop seven depots over the AA4 period to provide fit for purpose facilities to Western Power personnel. The eighth depot project relates to the Network Control Centre and Backup Control Centre, currently being delivered and considered in addition to the program. Each of the eight projects are considered on a standalone basis with business case approvals obtained in accordance with Western Power's delegated financial authority and its investment governance framework.

692. Western Power's 2016/17 efficient base year included a recurrent saving of $1.1 million arising from the Depot [redacted] Program. Additional savings to be delivered from the [redacted] depots over the AA4 period are included in the $12 million recurrent downwards step change in indirect costs provided in our operating and indirect cost forecast.

693. The Depot [redacted] Program has already commenced and is expected to be delivered in full during the AA4 period. Western Power has recently commenced the delivery and construction of a new fit for purpose depot at Vasse.

Table 6.28: Schedule of depot work

No#	Project	Expected completion
1	[redacted]	Late 2018
2	[redacted]	Late 2020
3	[redacted]	Mid 2020
4	[redacted]	Early 2021
5	[redacted]	Late 2021
6	[redacted]	Mid 2020
7	[redacted]	Mid 2021
8	[redacted]	End 2020

6.4.6 Forecast corporate capital expenditure

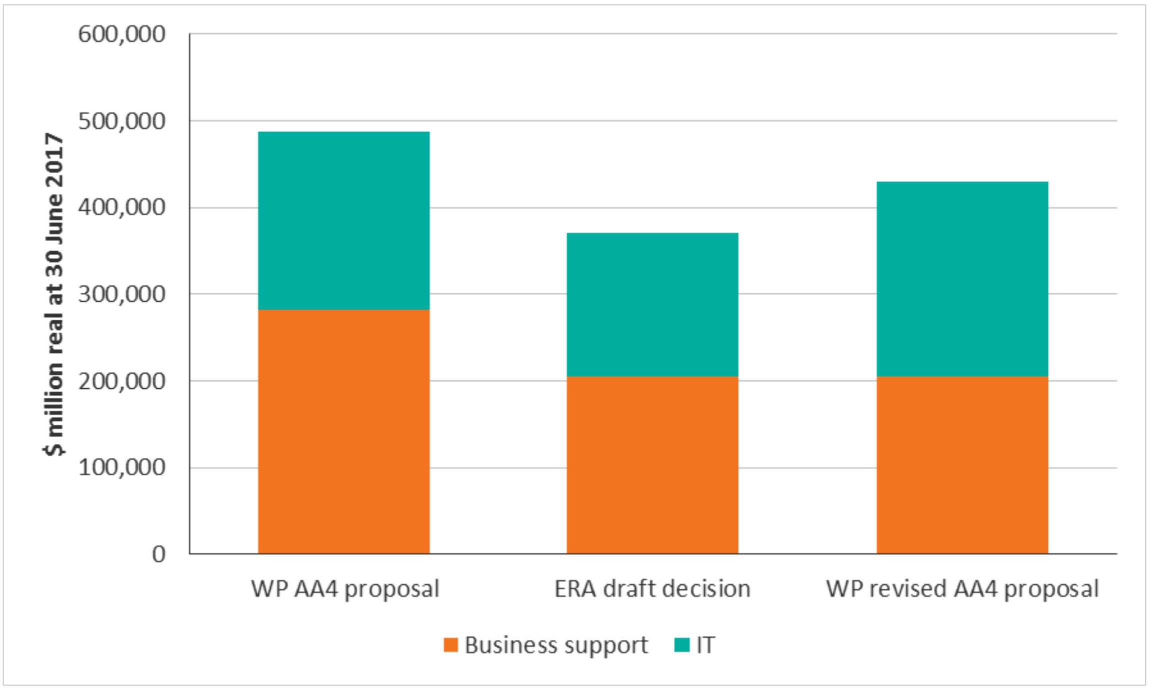
694. Taking into consideration the ERA's draft decision and the resulting adjustment for forecast capital expenditure, the revised AA4 forecast corporate capital expenditure is presented in the following table.

[144] Paragraph 480, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Table 6.29: Revised AA4 proposal on corporate capital expenditure direct costs ($ million real, June 2017) excluding gifted assets and cash contributions

Corporate capex	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Corporate real estate	23.3	43.2	116.6	9.9	8.1	201.1
Property, plant & equipment	0.8	0.8	0.8	0.8	0.8	4.2
Total business support	**24.2**	**44.1**	**117.4**	**10.7**	**8.9**	**205.3**
Business driven	48.7	48.5	30.3	22.6	18.6	168.7
Business infrastructure	8.5	12.1	17.0	10.8	7.0	55.3
Total IT	**57.2**	**60.5**	**47.3**	**33.4**	**25.6**	**224.1**
Total corporate	**81.4**	**104.6**	**164.7**	**44.2**	**34.5**	**429.4**

Figure 6.15: Comparison of corporate direct costs ($ million real, June 2017) excluding gifted assets and cash contributions



6.5 Forecast depreciation

695. In the AA4 proposal, Western Power retained the current depreciation approach, which requires depreciation to be calculated using:

- the straight line depreciation method
- the existing residual asset lives for assets that are included in the capital base at the beginning of the access arrangement period (i.e.2006)

- asset lives specified in the access arrangement for capital expenditure during the access arrangement period (i.e. AA1 to AA4).

696. The ERA is *satisfied that this approach is consistent with applying the roll-forward calculation in a manner consistent with the Code objective.*[145]

697. Western Power also proposed that the economic lives for electronic meters installed from the AA4 period onwards be changed to 15 years (from 25 years), as electronic meters have a shorter standard life than mechanical meters. The ERA accepts this change and also requires Western Power to review its existing metering assets to identify the current asset life is consistent with the economic life of those assets.

698. We have reviewed the metering assets in the network and can confirm that all meters installed during the AA3 period were electronic meters with a 15-year life. Therefore as per the ERA's requirement, we have also adjusted the economic lives for these existing electronic meters from 25 to 15 years.

699. The ERA also requires that the section of the access arrangement stating Western Power will apply accelerated depreciation to any network assets decommissioned as a result of the State Underground Power Program (SUPP) be reinstated. Western Power did not propose any accelerated depreciation as a result of SUPP in the AA4 proposal, however the ERA found this to be inconsistent with the requirements of the Access Code. The ERA also requires Western Power to *include details of redundant assets resulting from SUPP or any other programs that lead to in-service assets being removed.*[146]

700. We accept this requirement and have made the necessary amendment in the revised proposed access arrangement. Details of redundant assets are provided in the access arrangement and revenue model.

701. Depreciation of forecast capital expenditure within the proposed access arrangement is calculated based on forecast expenditure that is approved by the ERA. If there is a mismatch between actual and forecast expenditure, the access arrangement adjusts the annual RAB depreciation in subsequent years for the remainder of the asset useful life in order to fully depreciate the asset at the end of its standard life. In the event actual capital expenditure is lower than the total forecast depreciation during the period, the ERA has amended the revenue model to recover the whole amount of RAB over-depreciation in the first year of the subsequent period. Western Power accepts this approach.

702. Taking the ERA's draft decision into consideration and reflecting our revised proposed capex forecasts, the forecast depreciation amounts for inclusion in the AA4 forecast RAB are presented in the following table.

Table 6.30: AA4 forecast depreciation ($ million nominal)

	2018	2019	2020	2021	2022
Transmission	112.2	122.4	134.8	148.8	157.6
Distribution	263.1	292.1	309.2	315.6	317.0

6.6 AA4 forecast RAB calculation

703. The ERA made an amendment in the revenue model to account for the entire redundant/disposal amount of an asset in the year of disposal. Western Power accepts this amendment.

145 Paragraph 503, ibid.
146 Paragraph 510, ibid.

704. In the AA4 proposal, asset disposals were netted off against the annual capital expenditure before being depreciated over the standard life of the asset. However, we have modified our approach to align with the ERA's view.

705. Western Power also accepts the ERA's amendment in the revenue model calculating the equity raising costs to be capitalised for the transmission and distribution network.

706. Taking into account the ERA's draft decision, the adjustments to new facilities investment discussed in section 6.1 of this revised AA4 proposal, forecast depreciation, and the ERA's adjustment to asset disposals and equity raising costs, the revised AA4 forecast transmission and distribution RABs are presented in the following tables.

Table 6.31: AA4 forecast transmission RAB ($ million real, June 2017)

	2018	2019	2020	2021	2022
Opening RAB	3,113.8	3,156.9	3,264.7	3,381.9	3,424.7
Net capital expenditure	153.3	225.9	244.8	181.1	172.6
Forecast depreciation	110.1	118.0	127.7	138.3	143.9
Closing RAB	3,156.9	3,264.7	3,381.9	3,424.7	3,453.4

Table 6.32: AA4 forecast distribution RAB ($ million real, June 2017)

	2018	2019	2020	2021	2022
Opening RAB	5,827.1	6,061.5	6,292.1	6,539.8	6,671.0
Net capital expenditure	492.8	512.2	540.4	424.6	425.1
Forecast depreciation	258.3	281.6	292.7	293.4	289.4
Closing RAB	6,061.5	6,292.1	6,539.8	6,671.0	6,806.6

7. Return on regulated asset base

707. This section details Western Power's response to the ERA's required amendment to the regulated return on the RAB, also known as the weighted average cost of capital (WACC).

ERA required amendment 7:

Western Power must amend the (nominal after-tax) weighted average cost of capital to 6.00 per cent, based on the parameters set out in Table 75 of this draft decision and reasoning detailed in Appendix 5 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

708. In the AA4 proposal, Western Power broadly applied the WACC estimation methodology used by the ERA in its 2015 and 2016 access arrangement decision for ATCO Gas Australia and Dampier to Bunbury Natural Gas Pipeline (DBNGP) respectively. As a result, Western Power and the ERA are aligned on most WACC parameters, and we accept many of the ERA's amendments in principle.

709. However, one WACC parameter on which we remain of a different view to the ERA is the market risk premium (MRP). In its draft decision, the ERA submits the MRP is 6.2 per cent, compared to the 7.6 per cent we put forward in the AA4 proposal. In response to the draft decision we have revised our MRP point estimate, but we remain concerned about the way the ERA's MRP point estimate has been selected.

710. We do not consider a point estimate of 6.2 per cent is reasonable, based on the evidence, and does not give rise to a rate of return that meets the Access Code objective or price control objective of providing Western Power with the opportunity to earn a return on investment commensurate with the commercial risk involved.

711. Our concerns and our alternative estimate of the MRP is explained in further detail in the following section, however, in summary we submit that the MRP estimate should be 6.6 per cent, drawn from the mid-point of the ERA's MRP range. For the reasons explained, we consider this estimate to meet the Access Code objective and the price control objective and should be accepted.

712. As shown in Table 7.1 the MRP is the only WACC parameter we have not adopted in this revised AA4 proposal. Our WACC estimate adopts all the ERA amendments in full, and results in a nominal after-tax WACC of 6.12 per cent.

Table 7.1: Summary of Western Power's revised AA4 WACC proposal

WACC parameter	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Averaging period	30 June 2017	29 March 2018	29 March 2018	Western Power accepts this amendment
Nominal risk free rate	1.99	2.37	2.37	Western Power accepts this amendment
Equity beta	0.7	0.7	0.7	Western Power accepts this amendment

WACC parameter	WP AA4 proposal	ERA draft decision	WP revised AA4 proposal	Summary
Market risk premium	7.5	6.2	6.6	Western Power does not accept this amendment and proposes a modified point estimate
Nominal after tax return on equity	**7.24**	**6.71**	**6.99**	
Five-year interest rate swap (effective yield)	2.290	2.590	2.590	Western Power accepts this amendment
Debt risk premium	2.790	2.613	2.613	Western Power accepts this amendment
Benchmark credit rating	BBB-/BBB/BBB+	BBB+	BBB+	Western Power accepts this amendment
Term of debt for debt risk premium	10 years	10 years	10 years	Western Power accepts this amendment
Debt issuing costs	0.125	0.100	0.100	Western Power accepts this amendment
Debt hedging costs	0.114	0.114	0.114	Western Power accepts this amendment
Nominal cost of debt (return on debt)	**5.32**	**5.42**	**5.42**	Western Power accepts this amendment
Debt proportion (gearing)	60	55	55	Western Power accepts this amendment
Forecast inflation rate	1.64	1.84	1.84	Western Power accepts this amendment
Franking credits (gamma)	40	40	40	Western Power accepts this amendment
Corporate tax rate	30	30	30	Western Power accepts this amendment
Nominal after-tax WACC	**6.09**	**6.00**	**6.12**	
Real after-tax WACC	**4.38**	**4.08**	**4.21**	

7.1 Market risk premium

713. Western Power proposes a different estimate of the MRP to that adopted by the ERA in its draft decision. In the AA4 proposal, we submitted a paper from HoustonKemp that outlined our concerns with the way the MRP is set. In response, the ERA commissioned Pink Lake Analytics to assess the validity of these concerns.

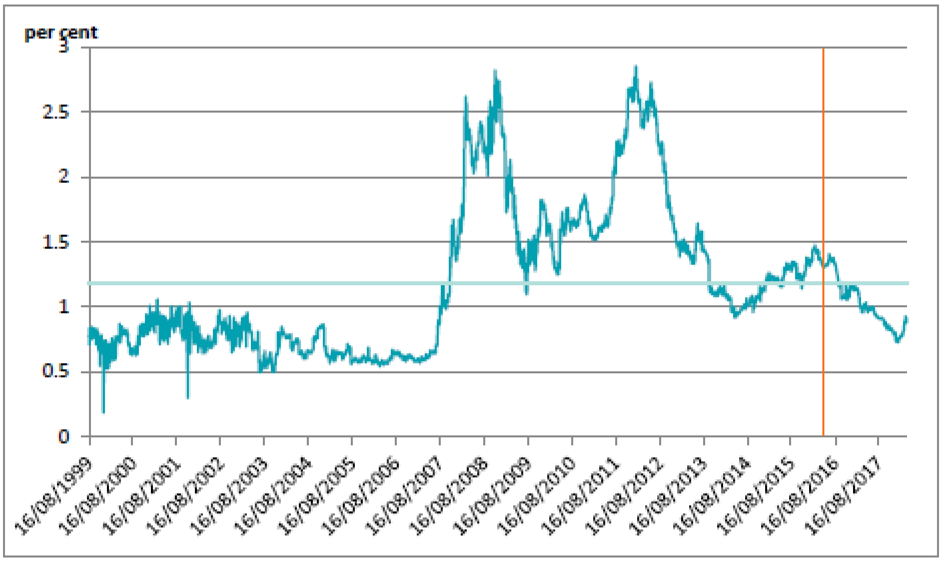
714. Though Pink Lake Analytics provided a response to each issue raised by HoustonKemp, we still have concerns regarding the MRP estimate. Our primary concern is the way the point estimate of the MRP has been selected from within the range of estimates. As we understand the ERA's MRP method, the ERA estimates a lower and upper bound for MRP and then selects a point between these two bounds based on forward-looking indicators and regulatory discretion.

715. We consider adopting forward-looking indicators to inform the point estimate of the MRP is reasonable. However, the point estimate selected from within the range must be reasonably based and reflect proper consideration of the evidence.

716. We are concerned that the interpretation of the forward-looking indicators (also referred to as conditioning variables) used in the ERA's draft decision is significantly different to its interpretation of essentially the same set of conditioning variables in its 2016 DBNGP final decision.

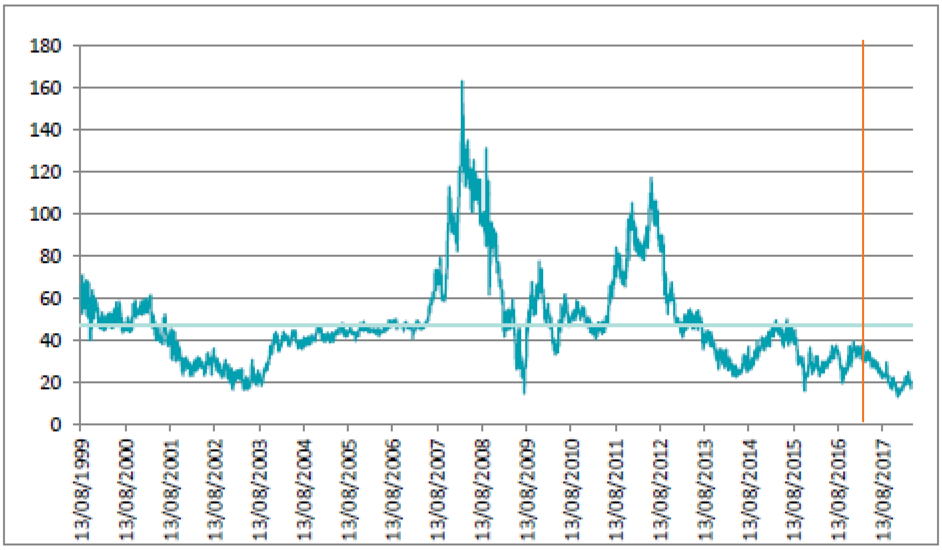
717. Figures 1 to 4 in Appendix 5 of the ERA's draft decision show the four forward-looking indicators used to determine the MRP point estimate. These are reproduced below, and we have added an orange line to identify the position of each indicator at the time of the DBNGP decision (June 2016).

Figure 1. **AA bond five year default spread from 1999 to 2018**



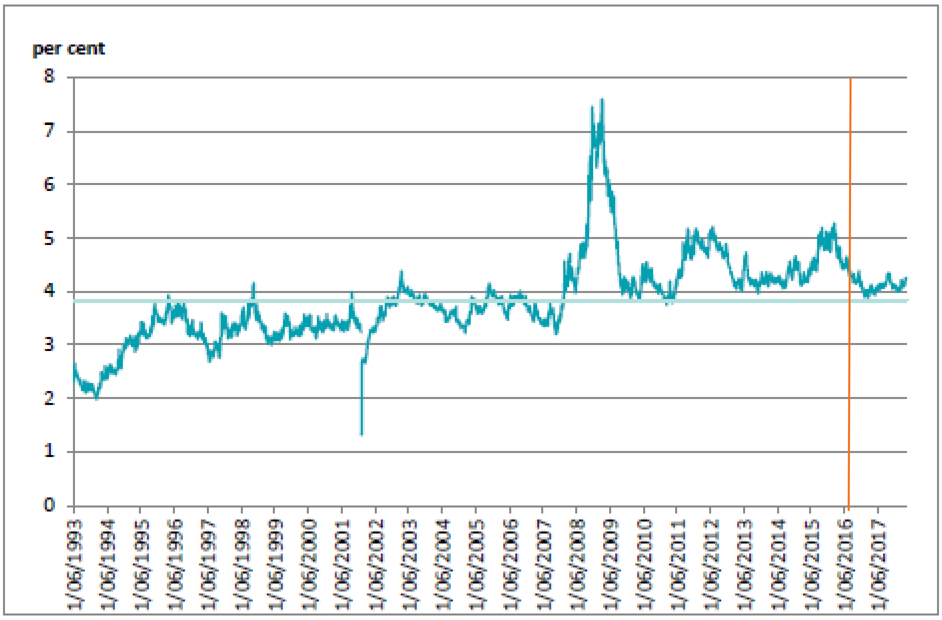
Source: ERA Analysis, Bloomberg Data

Figure 2. **Five year interest rate swap spread to Commonwealth Government bond (basis points) from 1999 to 2018**



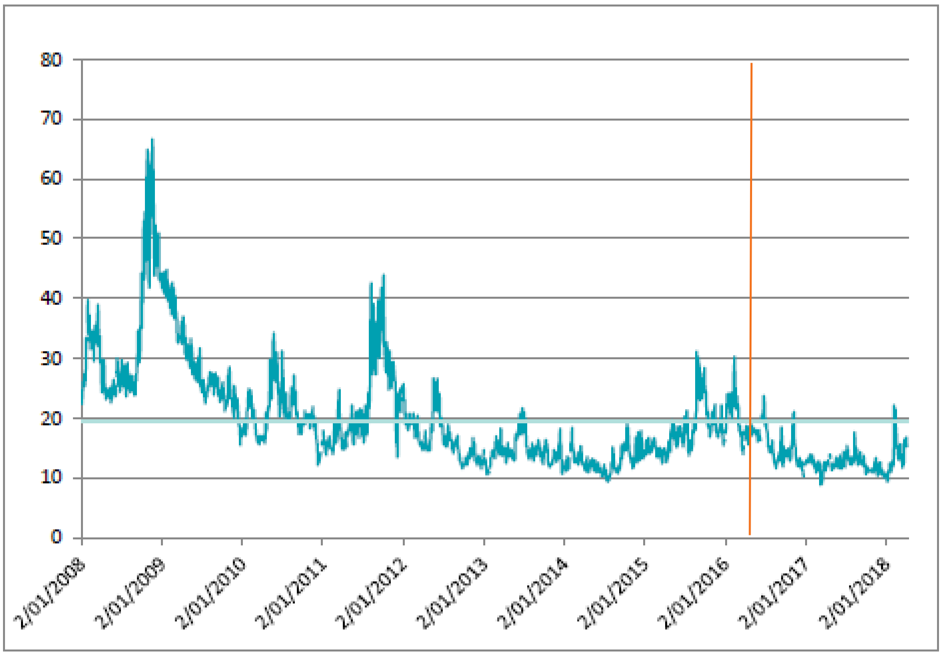
Source: ERA Analysis, Bloomberg Data

Figure 3. All Ordinary Index annual dividend yield from 1993 to 2018



Source: ERA Analysis, Bloomberg Data

Figure 4. Implied volatility (ASX200 VIX) from 2008 to 2018



Source: ERA Analysis, Bloomberg Data

718. In all cases other than the default spread (ERA's Figure 1), the variables were at almost exactly the same level at the time of the DBNGP decision as they are now. The ERA's decision at that time was for a point estimate at the 60th percentile; that is above the mid-point.

719. However, in the AA4 draft decision, using essentially the same forward-looking data, the ERA has determined the appropriate point estimate is at the 30th percentile (6.2 per cent from within a range of 5.6 per cent to 7.6 per cent).

720. As stated by the ERA in paragraph 182 of Appendix 5 of the ERA's draft decision:

> *To determine a point estimate for the market risk premium the ERA used four conditioning variables/forward looking indicators and regulatory discretion.*

721. This is a reasonable approach. Given the challenge is to estimate a forward-looking rate of return, with one of the key parameters being a forward-looking MRP, it is reasonable to draw more heavily on the forward-looking indicators when determining an appropriate MRP point estimate for the next five years.

722. The market data used to inform an MRP decision in June 2016 has not substantially changed 18 months later. However, the ERA now says that the forward looking indicators support an MRP estimate around the lower end of the range. The ERA does not adequately explain what has changed in its consideration of essentially the same conditioning variables that has led it to arrive at a materially different approach to arriving at the point estimate of the MRP (i.e. the 30th percentile from within the range rather than the 60th percentile). Based on the evidence, Western Power does not consider there to be a reasonable basis for a point estimate of 6.2 per cent.

723. We note the commentary in Appendix 5 relating to each measure relies on the fact that the current value is within a standard deviation of the long range estimate. While this may be the case, we do not consider it compelling evidence that a point estimate at the lower range is reasonable. In fact, a point estimate of 6.2 per cent is the lowest estimate of the MRP of any recent regulatory decisions by the ERA or the AER. The sharp decline in the estimate, which is not based on any evidence of a sharp decline in the updated estimates of the MRP, gives rise to regulatory uncertainty that is not consistent with promoting economic efficient investment and operation of the network as required by the Access Code objective.

724. We note that in paragraph 183 of the Appendix 5 of the ERA's draft decision, it states:

> *Conditioning variables are readily available market data which allow the ERA to take into account current market conditions. Conditioning variables should be considered symmetrically through time to avoid bias.*

725. The ERA has not qualified the second part of this statement in that conditioning variables should be considered symmetrically through time. Nonetheless, the view that conditioning variables should be considered symmetrically, all being equal, suggests selecting the mid-point of the variable is a reasonable approach.

726. As described in paragraph 22 of the ERA's draft decision:

> *If the ERA considers the Access Code objective and requirements of chapter 5 are satisfied it must approve the access arrangement. The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5.*

727. Western Power accepts the ERA's range for the MRP, but proposes a point estimate of 6.6 per cent reflecting the mid-point of the range. We consider this mid-point is consistent with the evidence of MRP estimates and in particular, the market data, conditioning variables and recent regulatory decisions.

728. An MRP estimate consistent with prevailing estimates of the MRP and with recent regulatory decisions on MRP will represent an effective means of achieving the Access Code objective as required by section 6.6 of the Access Code. We consider that this estimate better reflects the evidence of MRP estimates and will

therefore promote the economically efficient investment in and operation and use of the network. The ERA should find itself satisfied that Western Power's revised MRP estimate of 6.6 per cent meets the Access Code objective and approve the estimate as required by section 4.28 of the Code.

729. The ERA's approach of selecting the low end of its range and estimate of 6.2 per cent is not consistent with the evidence of the MRP nor recent regulatory decisions. Not only does this estimate not give rise to a return which is commensurate with the commercial risks involved, but the significant drop in the estimate from previous ERA MRP estimates, unsupported by any strong evidence that there has been such a drop in the estimates, gives rise to significant regulatory uncertainty which is not consistent with achieving the Code objective.

730. For the reasons set out we submit that the MRP for the AA4 period should reflect the mid-point of the ERA's MRP range, which is 6.6 per cent, and that this point estimate should be approved by the ERA.

8. Return on working capital

731. This section details Western Power's response to the ERA's required amendment to the return on working capital.

ERA required amendment 8:

The values of smoothed target revenue, forecast new facilities investment, forecast non-capital costs and weighted average cost of capital used to calculate working capital must be adjusted to be consistent with this draft decision.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

732. In the AA4 proposal, Western Power submitted it would continue using the same method and assumptions for determining the cost of working capital as approved for AA3. The ERA accepted the proposed working capital forecasting method on the provision that:

> *Western Power to provide updated information with its response to the draft decision to support its statement that there has been no change in the number of debtor days, creditor days or the proportion of inventory compared with capital expenditure since AA3.*[147]

733. We submit the following updates to working capital parameters:

Inventory

734. During the AA3 review process, Western Power submitted an inventory percentage of 6 per cent as calculated based on inventory as a percentage of its approved works program. However, the ERA did not approve this figure and maintained its position from the draft decision and used the average level of inventory value to works program size for other Australian service providers (4 per cent).

735. Though the inventory percentage of the AA4 approved works program is again likely to be in the order of 6 per cent, we propose to maintain the 4 per cent estimate approved for AA3.

Creditors

736. In line with the ERA's approach taken during its AA3 Further Final Decision for Western Power, Western Power has calculated creditors days payable at 26.09 days.

737. Based on the expenses in Western Power's 2017 annual report the expense weightings are 39 per cent for labour, 33 per cent for materials and 28 per cent other, with 10 days, 42 days and 30 days payable accordingly.

Receivables

738. Meter reading cycles are determined in accordance with the service level agreement for conducting a scheduled reading of the meter. At the time of writing, there had been no amendments to the model service level agreement (MSLA) approved by the ERA on 30 March 2006. The MSLA provides for the

[147] Paragraph 532, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

majority of meters (type 6260) to be read on bimonthly basis using best fit schedule route optimisation. Other types of meters (type 1 to 5261) are read on a monthly basis

Prepayments

739. No working capital requirements for prepayments have been identified.

740. We have not implemented required amendment 8 as proposed by the ERA, as we have made modifications elsewhere that affect the calculation of the return on working capital, for example the WACC. Our calculation of working capital is presented in the following tables.

Table 8.1: Proposed cost of working capital – transmission network ($ million nominal)

Transmission network working capital	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed target revenue	289.5	314.0	368.2	413.1	461.6
Expenses					
Forecast capital expenditure	156.1	234.3	258.6	194.8	189.0
Forecast operating costs	95.7	88.0	89.9	94.4	96.5
Total expenses	251.8	322.3	348.5	289.3	285.6
Working capital requirement					
Opening balance	18.3	23.9	25.0	30.8	38.0
Receivables (45 days)	35.7	38.7	45.3	50.9	56.9
Creditors (26.09 days)	6.2	9.4	10.3	7.8	7.6
Inventory (4% of capex)	-18.0	-23.0	-24.8	-20.7	-20.4
End of year working capital	23.9	25.0	30.8	38.0	44.1
Return on working capital at WACC = 6.12	**1.1**	**1.5**	**1.5**	**1.9**	**2.3**

Table 8.2: Proposed cost of working capital – distribution network ($ million nominal)

Distribution network working capital	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed target revenue	1,215.4	1,236.5	1,271.9	1,287.8	1,307.1
Expenses					
Forecast capital expenditure	506.3	538.4	575.4	456.7	465.7
Forecast operating costs	297.7	278.4	285.0	299.8	308.2
Total expenses	804.0	816.8	860.4	756.6	773.8
Working capital requirement					
Opening balance	118.9	112.6	115.6	118.1	123.0
Receivables (45 days)	149.8	152.5	156.4	158.8	161.1
Creditors (26.09 days)	20.3	21.5	23.0	18.3	18.6
Inventory (4% of capex)	-57.5	-58.4	-61.3	-54.1	-55.3

Distribution network working capital	2017/18	2018/19	2019/20	2020/21	2021/22
End of year working capital	112.6	115.6	118.1	123.0	124.5
Return on working capital at WACC = 6.12	7.3	6.9	7.1	7.2	7.5

9. Taxation

741. This section details Western Power's response to the ERA's required amendment to taxation costs.

> **ERA required amendment 9:**
>
> Forecast taxation costs must be updated to be consistent with the draft decision and must be allocated between services based on the proportion of revenue. The K-factor must not be included in the calculation.
>
> **Western Power's response:**
>
> Western Power accepts this amendment in principle, with modifications.

742. Western Power accepts this amendment in principle. However, the values used to calculate forecast taxation cost in this revised AA4 proposal are different to those used in the ERA's draft decision. This is because we have determined different values for the parameters used to calculate tax (e.g. revenue, opex and capex).

743. We also propose variations to the ERA's tax forecasting methodology. These are described in the following sections.

9.1 K-factor adjustment

744. The ERA has determined that the revenue under-recovery from the AA3 period should not be included in the taxable income for the benchmark tax calculation of AA4, as it has already been taken account of in the AA3 allowance. Essentially, the K-factor must not be included in the calculation. We accept this amendment and have made the change accordingly.

745. We have also removed the revenue adjustment relating to the investment adjustment mechanism (IAM) from the tax calculation. As highlighted by the ERA in paragraph 135 of its AA3 further final decision:

> *The IAM revenue includes a component for the return on capital based on the second access arrangement period weighted average cost of capital, and is calculated inclusive of tax liabilities. On this basis, similar to the k factor, to include IAM revenue for tax purposes in the third access arrangement would lead to a double count of the related tax liabilities.*[148]

746. The k-factor exclusion results in a downward tax cost adjustment and the IAM exclusion results in an upward tax cost adjustment. This is shown in tables 9.1 to 9.3.

9.2 Equity raising cost tax depreciation method

747. The ERA's draft decision applies an adjusted diminishing value depreciation calculation for equity raising costs. We do not accept equity raising costs should have a different depreciation calculation to other assets. A consistent depreciation methodology should be applied to all assets and given this approach was deemed appropriate during the AA3 period, we consider it promotes the Access Code objective. We have

[148] Paragraph 135, *Further Final Decision on Proposed Revisions to the Access Arrangement for the Western Power* Network, ERA, November 2012.

therefore applied the same depreciation calculation to equity raising costs as all other assets for tax depreciation purposes.

9.3 Tax allocation method

748. The ERA considers the tax allocation method between the distribution and transmission business should be changed so that the allocation is based on the proportion of revenue for each service. However, the ERA's method does not take into account the different levels of expenses incurred by each of the networks or the profitability of the distribution and transmission businesses independently. The transmission and distribution networks operate as separate entities and can/will be at different points of profitability at any given time.

749. We have therefore not made the ERA's amendment to allocate tax based on percentage of revenue earned. We have instead determined the tax amounts for each network independently, and allocated the total tax liability based on weightings of the calculated amounts.

750. Allocating tax between the distribution and transmission businesses (rather than based on revenue per service) more accurately reflects Western Power's actual business structure and tax position, and therefore better promotes the Access Code objective.

9.4 Revised AA4 tax cost estimate

751. The revised AA4 proposal forecast tax calculations are set out in the following tables.

Table 9.1: Estimated cost of corporate income tax for the AA4 period ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Western Power - Taxable income	347.3	336.9	419.6	429.8	495.7
Estimated cost of corporate income tax	104.2	101.1	125.9	128.9	148.7
Less value of imputation credits	-41.7	-40.4	-50.4	-51.6	-59.5

Table 9.2: Corporate income tax allocation to transmission cost of services for the AA4 period ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Tax payable	0.0	0.0	4.8	37.9	59.1
Less value of imputation credits	0.0	0.0	-1.9	-15.1	-23.6

Table 9.3: Corporate income tax allocation to distribution cost of services for the AA4 period ($ million nominal)

$M	2017/18	2018/19	2019/20	2020/21	2021/22
Tax payable	104.2	101.1	121.1	91.1	89.6
Less value of imputation credits	-41.7	-40.4	-48.4	-36.4	-35.9

10. Adjustments to target revenue

752. This section details Western Power's response to the ERA's required amendments to AA4 revenue adjustments related to performance and/or expenditure during the AA3 period. This section covers:

- AA3 investment adjustment mechanism (IAM) revenue adjustments
- AA3 gain sharing mechanism (GSM) revenue adjustments
- AA3 unforeseen events revenue adjustments.

10.1 Investment adjustment mechanism during the AA3 period

ERA required amendment 10:

Western Power must update the Investment Adjustment Mechanism value to reflect the ERA's draft decision on AA3 capital expenditure.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

753. Western Power accepts the principle of this amendment in that the IAM value has been updated to reflect the revised calculation of the AA3 closing RAB. However, our closing RAB calculation differs from the ERA's. As discussed in section 5.1.2, we consider the $28.9 million of wood pole emergency replacement costs should be included in the RAB, as these costs were not accounted for as opex during the AA3 period. Therefore we have not implemented this amendment exactly as required by the ERA.

754. The proposed IAM adjustment is shown in Table 10.2.

10.2 Gain sharing mechanism during the AA3 period

ERA required amendment 11:

Western Power must update the Gain Share Mechanism to reflect the ERA's draft decision on wood pole expenditure and unforeseen events and must allocate the value between services based on revenue proportions.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

755. Western Power accepts the principle of this amendment in that the GSM has been adjusted to reflect actual opex and the amounts recovered as an unforeseen event. However, our calculation of the GSM value differs from the ERA's due to our position on other required amendments.

756. We consider the $28.9 million of wood pole emergency replacement costs should be included in the RAB, as these costs were not accounted for as opex during the AA3 period. As discussed in section 10.3, we also maintain our position that costs relating to the EMR during AA3 be recovered via the unforeseen event

adjustment mechanism. Therefore we have not implemented this amendment exactly as required by the ERA.

757. The ERA requires the GSM allocation methodology between the transmission and distribution network to be based on the average revenue split of Western Power's smoothed revenue over the AA4 period. We have accepted the ERA's amended GSM allocation methodology.

758. The proposed GSM adjustment is shown in Table 10.2.

10.3 Unforeseen events during the AA3 period

ERA required amendment 12:

Western Power must adjust target revenue to remove its proposed unforeseen event adjustment.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

759. In the AA4 proposal, Western Power submitted a revenue adjustment to recover costs incurred during the AA3 period associated with the then State Government's Electricity Market Review (EMR). Western Power incurred operating costs of $18.7 million and capital costs of $6.4 million to respond to and facilitate the electricity market reforms being imposed upon it.

760. Phase 2 of the EMR was announced in March 2015[149] and laid out specific market reforms including the transfer of network regulation to the National Electricity Rules (NER), which imposed significant mandatory costs on Western Power. This was followed by an announcement in September 2015[150] that Western Power's system management function and the Independent Market Operator would transfer to the AEMO.

761. Following further design work, the Government announced on 23 June 2016 that *legislation enabling the transfer of the regulation of WA's electricity network to the Australian Energy Regulator (AER)* had been introduced to State Parliament and that *Western Power's next regulatory control period would start with the AER on 1 July 2018.*[151] This was followed by an announcement on 26 July 2016[152] regarding major reforms to the wholesale electricity market and operation of the electricity system, which would also come into effect on 1 July 2018.

762. The timelines for delivery of the major market reforms included:

- transfer of system management functions to the AEMO by 1 July 2016
- submission of a regulatory proposal to the AER by 1 April 2017
- commencement of the first regulatory period under the National Electricity Rules (NER) framework on 1 July 2018
- implementation of constrained network access from 1 July 2018.

[149] 24 March 2015 - https://www.mediastatements.wa.gov.au/Pages/Barnett/2015/03/Government-energised-for-electricity-reform.aspx
[150] 30 September 2015 - https://www.mediastatements.wa.gov.au/Pages/Barnett/2015/09/Electricity-reform-gains-momentum.aspx
[151] 23 June 2016 - https://www.mediastatements.wa.gov.au/Pages/Barnett/2016/06/Legislation-paves-the-way-for-energy-reforms.aspx
[152] 28 July 2016 - https://www.mediastatements.wa.gov.au/Pages/Barnett/2016/07/New-reforms-to-WA-wholesale-electricity-market.aspx

763. Western Power had to incur costs to enable its transition to the NER regulatory framework, as well as the transfer of its System Management function to the AEMO, within the mandated time frames.

764. The EMR was not foreseen at the beginning of the AA3 period, therefore no forecast costs were included in the AA3 decision. Costs associated with EMR are not recoverable under Western Power's insurance policies.

765. EMR costs incurred by Western Power during the AA3 period covered three work streams:

- network regulation – preparation of Western Power's regulatory submission to the AER
- market competition – contestability, connections and access
- institutional arrangements – transfer of System Management to the AEMO.

766. Western Power also incurred program management costs to manage and coordinate the significant volume of work being done to facilitate the reforms.

767. In its draft decision, the ERA does not allow a revenue adjustment for any EMR costs. One of its key reasons for this decision is that:

> *The ERA does not consider developing or responding to possible energy reform meets the Access Code requirements for a force majeure event. Energy policy is an ongoing process and should be part of normal business for any network service provider.*[153]

768. Western Power does not agree with the ERA's interpretation that the EMR costs do not meet the definition of force majeure or that they do not satisfy the requirements of 6.6 to 6.8 of the Access Code.

769. The Access Code defines force majeure as:

> ***"force majeure"****, operating on a person, means a fact or circumstance beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome.*

770. The EMR costs were a direct result of the Government's decision to *develop legislation enabling the transfer the regulation of Western Australia's electricity network to the AER.*[154] This circumstance was not foreseen when the AA3 revenue determination was made in 2012, and can reasonably be considered to satisfy the Access Code definition of force majeure.

771. With regard to the ERA's assertion that:

> *The ERA notes there was no regulatory obligation for this submission* [to the AER] *to be prepared.*[155]

772. The Access Code does not require a regulatory obligation to be implemented for an event to be considered unforeseen. The Access Code definition for force majeure applies. The definition of force majeure simply requires a *fact or circumstance* to have occurred. The Government's proposed transfer of the regulation of Western Power to the AER is such a fact or circumstance.

773. It is unreasonable to consider Western Power had no cause to take action, particularly given the June 2016 Ministerial announcement regarding the transfer of regulation to the AER. At the time there was no reason to conclude that the transition would not occur as planned or that no action was required on Western

[153] Paragraph 603, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[154] 23 June 2016 - Media statement, Hon Mike Nahan MLA, Minister for Energy – Legislation paves the way for energy reforms.

[155] Paragraph 602, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA. May 2018.

Power's part. The only question is whether, in the face of the event (the Government announcements and communications with Western Power), Western Power's response meets section 6.8 of the Access Code.

774. The unforeseen events provisions of the Access Code are as follows:

Target revenue may be adjusted for unforeseen events

6.6 If:

(a) during the previous access arrangement period, a service provider incurred capital-related costs or non-capital costs as a result of a force majeure event; and

*(b) the service provider was unable to, or is unlikely to be able to, recover some or all of the costs (**"unrecovered costs"**) under its insurance policies; and*

(c) at the time of the force majeure event the service provider had insurance to the standard of a reasonable and prudent person (as to the insurers and the type and level of insurance),

then subject to section 6.8 an amount may be added to the target revenue for the covered network for the next access arrangement period in respect of the unrecovered costs.

6.7 Nothing in section 6.6 requires the amount added under section 6.6 in respect of unrecovered costs to be equal to the amount of unrecovered costs.

6.8 An amount must not be added under section 6.6 in respect of capital-related costs or non-capital costs, to the extent that they exceed the costs which would have been incurred by a service provider efficiently minimising costs.

775. We submit that the EMR costs satisfy the requirements of section 6.6 in that a force majeure event occurred and Western Power was unable to recover these costs under its insurance policies (which were in place at the time of the force majeure event and to the standard of a reasonable and prudent person).

776. With regard to sections 6.7 and 6.8, Western Power is only claiming recovery of its efficient costs – i.e. those which would have been incurred by a service provider efficiently minimising costs. As discussed in the AA4 proposal, Western Power is only claiming those costs that were directly related to the EMR, it is not claiming any indirectly related costs.

777. Western Power did not have the internal expertise or experience of the NER framework to be able to fully assess the implications of the reforms. We therefore procured additional external expertise through competitive tendering processes in order to progress and implement the reforms expediently and efficiently. The tendering process helped efficiently minimise these external consultancy costs.

778. In summary, we do not agree with the ERA's view that all of the activities associated with the EMR would form part of normal business for any network service provider. The EMR placed significant requirements on Western Power that were designed to re-shape the business' entire regulatory landscape. It is not reasonable to regard such a wide-reaching reform program as business-as-usual.

779. We therefore maintain that the efficient costs associated with EMR should be recovered via the unforeseen event adjustment mechanism. We have, however, revised the amounts we are seeking under the revenue adjustment. The revised AA4 unforeseen event proposal is described in the following section.

10.3.1 Revised unforeseen event revenue adjustment

10.3.1.1.1 Capex

780. In the AA4 proposal, we submitted that $6.4 million of capital expenditure related to the EMR should be recovered via the unforeseen event provisions. However, we accept the ERA's technical consultant's view (GBA*) that it is not usual to include intangible assets in the regulatory asset base of an electricity lines business.*[156]

781. We are therefore no longer seeking these capital costs as an unforeseen event revenue adjustment or for this capital expenditure to be added to the RAB.

10.3.1.1.2 Opex

782. In the AA4 proposal, we submitted that $18.7 million of operating expenditure relating to the EMR should be recovered via unforeseen event provisions. The operating costs incurred can be broken into four categories:

- network regulation – preparation of Western Power's regulatory submission to the AER
- market competition – contestability, connections and access
- institutional arrangements – transfer of System Management to the AEMO
- program management – EMR transition

783. Since the AA4 proposal, we have further scrutinised and subsequently adjusted the opex amounts we are claiming under the unforeseen events provision. The revised unforeseen event amounts are presented in Table 10.1 and discussed in the sections that follow.

Table 10.1: Opex amounts to be recovered via unforeseen events provisions ($ million real, June 2017)

EMR-related cost	AA4 proposal	Revised AA4 proposal
Network regulation – regulatory submission program	6.2	6.2
Market competition – contestability, connections and access	3.4	2.8
Institutional arrangements – System Management / AEMO	4.6	4.6
Program management – EMR transition	4.3	4.3
Total	**18.7**	**17.9**

784. Note, Western Power has proposed a $2.4 million adjustment to the 2016/17 revealed costs for permanent employees that had been allocated to the EMR project and therefore inadvertently removed from 2016/17 opex as a non-recurrent cost (discussed in section 4.1). For the avoidance of doubt, these internal labour costs have already been excluded from the totals Western Power is proposing to recover via the unforeseen event provisions per Table 10.1.

[156] Paragraph 313, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Network regulation – regulatory submission program

785. As discussed in the AA4 proposal, when we classified the force majeure costs we excluded any costs related to the EMR that may have been incurred even without the introduction of the review.

786. However, we maintain that $6.2 million of EMR-related costs were directly related to artefacts that had to be produced for the transition to the AER framework. These artefacts included:

- regulatory information notices (RINs) – for reporting to the AER
- expenditure forecast method – to comply with the AER forecasting method
- service classifications – to revise service classifications to be consistent with the classification of services defined in the NER
- transmission/distribution classification – to revise the distribution/transmission split to be consistent with the AER's requirements
- regulatory submission – to comply with the AER's guidelines
- revenue, contributions and pricing methods – consistent with the NER requirements
- cost allocation method – updated to be consistent with the NER requirements.

787. Western Power did not have sufficient experience of the NER requirements to be able to deliver the volume of work required within the time frames for the expected transition. Western Power followed its standard procurement processes, which included competitive tendering, to commission a number of expert consultants to help deliver the artefacts listed above.

788. The proposed transition to the NER framework required Western Power to undertake this work, and it should not be considered a business-as-usual activity. The artefacts were required for the submission to the AER due on 1 April 2017, and could not be re-used for the AA4 review with the ERA. Western Power would not have incurred these costs if the EMR had not imposed these obligations on it.

789. We submit that the $6.2 million expenditure associated with the network regulation work stream does not exceed the costs that would have been incurred by a service provider efficiently minimising costs, and should be recovered under the unforeseen event provisions of the Access Code.

Market competition – contestability, connections and access

790. In the AA4 proposal we submitted $3.4 million for recovery under the unforeseen event provisions. In this revised AA4 proposal we have excluded a further $0.6 million of opex related to market competition where we found we had not fully removed costs associated with business as usual staff who were time-sheeting to the project during the EMR.

791. We maintain that the $2.8 million incurred on the market competition contestability, connections and access work stream do not exceed the costs that would have been incurred by a service provider efficiently minimising costs. This opex was directly related to the proposed:

- introduction of contestable metering
- transition of the retail market operator function to AEMO
- introduction of new customer-network contracts to facilitate the 'triangular relationship' model
- transition to the connections and access framework under the NER
- transition to constrained network access

- removal of network access charges for generators and treatment of benefits provided to future generators.

792. All of these items were contemplated by the EMR and fall outside what could reasonably be considered business-as-usual activities. Work was conducted by expert consultants following a competitive tendering process.

793. Though the cancellation of the EMR in late 2016 means a number of these proposed changes did not materialise, Western Power had to undertake this work and could not reasonably have been expected to foresee that the EMR would not be delivered in full.

Institutional arrangements – System Management / AEMO

794. We maintain that the $4.6 million incurred on the System Management / AEMO separation do not exceed the costs that would have been incurred by a service provider efficiently minimising costs.

795. The System Management / AEMO separation process was staged over four milestones:

1. 30 June 2016 - milestone 1 legal separation – establishment of an interim operating agreement with legislative accountability for the System Management function transferring to AEMO, while people and processes remained with Western Power
2. 31 October 2016 - milestone 2 functional separation – establishment of a transfer agreement and service agreement enabling AEMO to use Western Power's System Management systems and facilities
3. 24 October 2017 - milestone 3 physical transition – AEMO personnel relocate to AEMO offices and facilities, while continuing to operate Western Power's System Management systems via a communications link
4. Date to be confirmed - milestone 4 – AEMO replaces Western Power's system and energy management systems with its own systems.

796. These $4.6 million of System Management / AEMO separation costs relate to the ICT, commercial and operating changes required to enable the functions that were formerly shared by Western Power and its System Management function to transfer to the AEMO. They include the commercial and legal works to establish the necessary contractual agreements and ensure Western Power's interests were protected. This includes the transfer or licensing (as appropriate) of System Management documents and other records, intellectual property, and other specified assets incidental to System Management (as agreed by the parties) from Western Power to the AEMO.

797. The ERA has incorrectly assumed Western Power would not have incurred any costs associated with the segregation of its network operations functions, processes and systems from those of System Management. It is inaccurate to assume all costs should have been borne by WEM participants.

798. For example, Western Power incurred ICT costs to ensure the network systems and processes that were formerly shared with System Management could continue to operate when System Management was segregated. Operating costs were also incurred to prepare technical constraint limit equations so that AEMO employees could use their system operation systems without being able to access Western Power's network operations systems.

799. The cost split of the communications link between Western Power and the AEMO was based on the number of technical units (e.g. servers and switches) required to support the AEMO requirement versus the number of units assigned to support Western Power obligations. The labour was then based on a percentage of effort across the install of those devices.

800. The separation of System Management from Western Power is not a business as usual activity, was not foreseen at the beginning of the AA3 period, and qualifies as a force majeure event.

801. Therefore we submit that the $4.6 million of opex relates to Western Power costs only, represent costs incurred by a prudent network operator efficiently minimising costs, and should be recovered under the unforeseen event provisions of the Access Code.

Program management – EMR transition

802. We maintain that the $4.3 million incurred on the EMR transition program management does not exceed the costs that would have been incurred by a service provider efficiently minimising costs.

803. These program management costs were driven by the separation of Western Power and System Management. They include the scoping, planning, change management, and consultancy costs required to ensure network operations can continue as part of the covered service with functional separation of the businesses. Program management costs include:

- consultancy costs associated with scoping and planning the work for the transition
- establishing operating protocols and defining the operational boundaries between the functions
- managing the transition of System Management staff from Western Power to the AEMO.

804. Western Power and the AEMO agreed the apportionment of costs to each party and formally documented these in a service level agreement. Under the service level agreement, Western Power and the AEMO assessed the total costs and the proportion that should be recovered from wholesale market participants and Western Power's customers.

805. The separation of System Management from Western Power is not a business as usual activity, was not foreseen at the beginning of the AA3 period, and qualifies as a force majeure event.

806. Therefore we submit that the $4.3 million of program management opex represent costs incurred by a prudent network operator efficiently minimising costs, and should be recovered under the unforeseen event provisions of the Access Code.

10.4 AA4 revenue adjustments

807. Table 10.2 shows the revised proposed revenue adjustment to be applied to AA4 target revenue as a result of performance against the various adjustment mechanisms in place during the AA3 period.

Table 10.2: Revenue adjustments under AA3 adjustment mechanisms ($ million real, June 2017)

Adjustment mechanism	Present value adjustment to AA4 transmission revenue	Present value adjustment to AA4 distribution revenue
Investment adjustment mechanism (IAM)	-33.5	-5.9
Gain sharing mechanism (GSM)	66.7	211.2
Service standard adjustment mechanism (SSAM)	13.4	241.3
D-factor	0.0	8.8
Unforeseen events	4.6	14.2
Technical Rules changes	0.0	0.0
Total	**51.2**	**469.6**

11. Reference and non-reference services

808. This section details Western Power's response to the ERA's required amendments to the proposed reference and non-reference services for the AA4 period. This sections covers:

- time of use reference services
- metering reference services
- definitions of reference services.

11.1 Time of use reference services

ERA required amendment 13:

The proposed new time of use reference services must not be mandatory.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

809. Western Power accepts this amendment and has made the necessary changes to Appendix E of the revised proposed access arrangement. The time of use reference services that were proposed by Western Power as reference services D1, D2, D3 and D4 are now not mandatory.

810. In the AA4 proposal, we proposed all new customers would receive an advanced meter and then be moved on to one of these new reference services. The aim was to move as many customers as possible on to a new, more efficient tariff structure to drive cost reductions over time. The new tariffs would achieve this by incentivising customers to consume energy (and therefore demand) away from the peak thereby delaying network upgrades (effectively meaning that the network is utilised more efficiently).

811. It is clear from the ERA and stakeholders' feedback that mandatorily implementing these reference services was not well supported.

812. We have therefore revised the access arrangement such that these references services are not mandatory. We still consider there are benefits associated with ensuring as many customers are on these new reference services as practicable, and as such will work with retailers to encourage the take up of these services and tariffs.

813. The time of use tariffs included in the AA4 proposal, as an interim step, were priced in such a way that they were effectively a flat rate tariff, similar to the existing A1 reference service that the majority of residential customers are on. As a result of removing the mandatory element of the time of use reference services, there is no longer a need for this interim step.

814. The time of use tariffs associated with the new reference services will now include a small amount of price variability across the different time periods. To ensure there are no price shocks, the price variability between the peak, off-peak and shoulder period charges will start at a low level. It is expected that over the AA4 period, as data improves in line with the installation of the advanced metering infrastructure (AMI), prices will be reviewed and refined, and greater differences will open up between the charges for the time periods. Of course, we will ensure this occurs gradually and is considered carefully.

815. Stakeholder feedback has also shown that there does not appear to be a significant desire for the introduction of new time of use based demand services as reference services. In this revised AA4 proposal, we have removed the demand based services D3 and D4 as reference services. If demand for these services emerges during the AA4 period, Western Power will encourage users to negotiate the provision of these services as a non-reference service.

816. Should significant demand for these demand based services emerge, they can be added as reference services for the AA5 period. This occurred during AA3, with a large number of non-reference services for bidirectional customers being agreed who would otherwise be eligible for reference services A5 – A8, leading to the inclusion of these services as reference services for the AA4 period.

11.2 Metering reference services

ERA required amendment 14:

Western Power must unbundle metering services from reference services and specify separate metering services as reference services based on the meter reading services required by users.

Western Power's response:

Western Power does not accept this amendment and proposed a modified position.

817. In its draft decision, the ERA has stated the following desired outcomes relating to metering services:

- clarity and detail on what standard meter services are provided[157]
- choice to users who seek a different level of metering.[158]

818. Western Power agrees with these objectives.

819. We also generally agree with the desired outcome in paragraph 727 of the ERA's draft decision, that recovery of metering costs should be more closely aligned with a user-pays basis and based on the cost of the service. We consider this is particularly relevant in respect of metering services that are beyond the minimum standard metering services.

820. Where Western Power differs from the ERA's view is in the manner by which these outcomes are achieved. We do not agree that unbundling metering services from the reference services proposed by Western Power and specifying separate meter reference services is necessary to achieve these outcomes. In fact, we consider unbundling these services would:

- not align with the legislative framework for metering in Western Australia
- lead to contractual issues under existing access contracts which contemplate one reference service (and one tariff and therefore charge) at each network connection point
- limit, rather than enhance, choice of metering services available to users
- result in additional costs to Western Power and other users to implement.

[157] Paragraph 715 and point 1 in paragraph 724, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[158] Paragraph 716 and point 2 in paragraph 724, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

821. The above points are discussed in the following sections.

11.2.1 Legislative metering framework

822. As identified by the ERA in its draft decision, metering is a supplementary matter under the Access Code (see section 5.27(c))[159]. A supplementary matter is one the access arrangement must deal with in accordance with relevant written laws that prescribe a regulatory framework separate from the economic regulatory framework of the Access Code. The separate regulatory framework takes precedence and the access arrangement must be consistent with and facilitate the legal instruments of that separate framework.

823. The ERA's required amendment 14 has the opposite effect. It overrides the operation of the *Electricity Industry (Metering) Code 2012 (WA)* (Metering Code) and its instruments by regulating metering services under the Access Code and the access arrangement.

824. The Metering Code provides the framework for regulating all aspects of metering including setting the:

- metering objectives (Part 2)
- requirements for meters and metering installations (Part 3)
- metering database and its processes (Part 4)
- regime for the provision of metering services (Part 5)
- requirements for the preparation and approval of a number of the underlying metering documents, including the Model Service Level Agreement (MSLA) (Part 6).

825. In contrast, the Access Code is a regulatory framework for access. It is an access framework directed to the price and non-price terms and conditions of access to the Western Power network. Access does, of course, include metering, but the Access Code prescribes that in the relationship between the economic regulatory framework and the metering regulatory framework, the metering regulatory framework takes precedence.

826. Examples of how the required amendment is inconsistent with and does not facilitate the Metering Code and its instruments include:

- section 5.1 of the Metering Code sets out the framework for Western Power to use all reasonable endeavours to accommodate a user's requirements for obtaining metering services and negotiate a service level agreement. The required amendment interferes with this framework, by seeking to designate a limited number of metering services as reference services which the user chooses
- section 6.6 of the Metering Code requires the contractual provision of metering services through an agreed written service level agreement or, if no such agreement is in place, the MSLA. The written service level agreements that Western Power has entered into and the 2006 MSLA (which Western Power agrees with the ERA is the relevant MSLA for considering AA4) include detailed descriptions of the metering services, relevant service standards and charging arrangements that Western Power must and may provide. These are matters the required amendment would move to the access arrangement as reference services, which would be impermissible under section 5.28 of the Access Code. It would also have the effect of overriding previously agreed and operating binding service level agreements
- section 3.2(2) of the Metering Code provides that Western Power can deem an interval capable meter an accumulation meter and only record accumulation data in the meter register. This section allows Western Power to only record accumulated energy data registered by the meter and a choice of

[159] Paragraph 709, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

interval meter read for such a meter would clearly be inconsistent with, and not facilitate, the Metering Code.

11.2.2 Contractual considerations

827. Under the current approved form of Electricity Transfer and Access Contract (ETAC) Western Power provides services defined as either an 'entry service', an 'exit service' or a 'bidirectional service'. There is no provision in the ETAC for a 'metering service'.

828. This position is reflected in each ETAC Western Power has entered into based on the current approved standard form of ETAC, as well as ETACs entered into on previous approved standard forms of ETAC (i.e. the standard form ETAC for AA1 and AA2), which contain similar contractual service provisions.

829. Currently, metering services get incorporated within the contracting framework because they are part of the bundled entry services, exit services and bidirectional services. If they are unbundled they will sit outside of the ETAC framework.

830. It is thus unclear how metering services would be provided and charged for under Western Power's existing ETACs. We do not consider it is an acceptable outcome to provide reference services that are not expressly contemplated by existing access contracts, thereby putting at risk the recovery of charges for the provision of those services.

831. Other contracting issues include:

- pursuant to the current approved form of ETAC users select services in accordance with the Applications and Queuing Policy (see clause 3.2 of the Policy). The Applications and Queuing Policy does not contemplate metering services, the Metering Code does this
- pursuant to the current approved form of ETAC users can make a bare transfer of the covered service at a connection point in accordance with Transfer and Relocation Policy. It is unclear how this will operate if there are two covered services (one access service and one metering service) at a connection point and whether these services can be dealt with separately such that the services are provided to different parties at the same connection point. This is likely to create issues as metering data is an essential element for calculating access charges.

11.2.3 Choice of metering services

832. Pursuant to section 5.2 of the Access Code Western Power's access arrangement must specify reference services that are likely to be sought by:

- a significant number of users and applicants; or
- a substantial proportion of the market for services in the covered network.

833. The ERA states Western Power should base its reference services on users' requirements, rather than on what Western Power thinks is required[160]. However, the structure of the Access Code is the reverse, in that it is Western Power that proposes its access arrangement according to how it considers the Access Code requirements are met. The ERA then, in accordance with the Access Code, considers whether or not to approve Western Power's proposal.

834. Nevertheless, we have taken on board the ERA's views that users seek different metering services of the general type described by the ERA in paragraph 726 of its draft decision and these should be designated as reference services. However, in the short time since receiving the draft decision, we have not had the

[160] Paragraph 659, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

opportunity to adequately investigate whether the criteria in section 5.2 of the Access Code are satisfied in respect of offering metering services as separate reference services, nor the manner in which meter reference services may be offered.

835. Further, the ERA has not identified why the bundled reference services proposed by Western Power in its AA4 proposal (which is how reference services were configured and approved in each of the three previous access arrangements) do not meet both of the criteria in section 5.2 of the Access Code. Therefore, the ERA must not refuse to approve the bundled reference services under section 4.28 of the Access Code.

836. In any event, we do not consider that unbundling metering services is necessary in order to give users choice of metering services. We consider the user will be able to (and has previously been able to) obtain the types of interval and other metering services identified in paragraph 726 of the ERA's draft decision as well as other more bespoke metering services. In fact, we consider there is more flexibility under the current arrangements for users to seek additional types of metering services.

837. As described above, the Metering Code deals with metering services. Pursuant to section 5.1 of the Metering Code Western Power is required to use all reasonable endeavours (and to act expeditiously, diligently and in good faith) to accommodate a user's requirements for obtaining metering services and to negotiate a service level agreement. It is within this negotiation framework that Western Power and users can (and do) negotiate and agree upon different metering services.

838. In terms of negotiating such services Western Power will continue to provide metering services that go beyond the standard metering service on a user-pays basis and based on the cost of the service.

11.2.4 Implementation costs

839. Western Power's existing meter registry and ICT billing systems only support the provision of one reference service (and charge) at each connection point on the Western Power Network. Unbundling metering services effectively creates two or more services (and charges) at each connection point.

840. The simplest way to facilitate multiple reference services and charges at a connection point is to use Western Power's existing meter registry and ICT billing systems but create new codes within these systems for each access reference service and metering reference service permutation and migrate the existing services to their applicable new code.

841. With hundreds of thousands of connection points and various new reference service and metering reference service permutations, this work (especially the transition work) is not insignificant. Our initial estimate is that it will cost approximately $1.8 million to implement this change. The implementation of new codes in Western Power's existing meter registry and ICT billing systems will also have an impact on users and AEMO. We understand this will likely result in additional costs to them.

11.2.5 Western Power's proposal

842. For the reasons detailed above, Western Power considers that the desired outcomes for metering are better achieved by maintaining bundled reference services and continuing to use the legislative framework provided under the Metering Code and MSLA for additional metering services. That said, we appreciate that more can be done to clarify how this occurs in practice. This clarity will stem from making clear what the standard metering service is for each reference service, as this will be the point from which users will negotiate additional metering services under the service level agreement framework provided for under section 5.1 of the Metering Code.

843. We consider that the appropriate place to clarify what the standard metering services are is within the MSLA (or the negotiated SLAs). The 2006 MSLA already identifies standard metering services and some of

the amendments proposed by Western Power in its revised MSLA seek to refine the description of these services further. We will revisit the proposed revised MSLA to see if more can be done to clarify what constitutes standard metering services. However, the revised MSLA is not approved and, as identified by the ERA in its draft decision, the reference services will need to be applied based on the 2006 version of the MSLA.[161]

844. As an interim step until the MSLA can be updated to provide further clarity on the standard metering services we propose the inclusion of a temporary annexure to Appendix E: Reference Service. This annexure shall be an explanatory guide document detailing the key aspects of the standard metering services that are included within each of the bundled reference services.

845. The annexure is designed to help users understand what the standard metering services are for each reference service and how they may go about requesting additional metering services they may require. We consider this temporary annexure will then fall away when the MSLA is updated.

846. The standard metering services in some ways can be seen as the minimum service Western Power will offer (with appropriate prices allocated to them) and anything above the minimum service is acquired either as an extended metering service under the MSLA or as an additional metering service through the negotiation framework under section 5.1 of the Metering Code.

847. In terms of pricing for these additional metering services, we will approach this more closely to a user-pays basis and the cost of the service. We will seek to charge for additional metering services based on the incremental cost of providing that service. That is, the price will be the cost of providing the additional metering service, minus the cost of any part of the standard metering service that is no longer required. For example, if a user requests a manual interval meter read and interval data where the standard meter service is an accumulation meter and accumulation data, then the price that will be applied will be the cost of the manual interval meter read minus the allocated cost (i.e. the tariff in the Price List) of the accumulation read.

848. This approach ensures users have choice of metering services to suit their individual needs. These choices will be appropriately priced (i.e. user pays and cost reflective) and most importantly, still operate within the current metering framework.

11.3 Definitions of reference services

ERA required amendment 15:

Western Power must amend Appendix E of the access arrangement in line with Table 117 of the draft decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

849. The ERA requires Western Power to make the amendments set out in Table 117 of its draft decision.

161 Paragraph 714, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

850. Table 117 of the ERA's draft decision is as follows:

Reference service	Amendment	Reason
D1-D4	Eligibility criteria to be stated in full instead of referring to another reference service	For clarity and ease of use, the information for each reference service should be included as a stand-alone document.
All services	Remove the term "compliance instruments" and replace with "Technical Rules, the Western Australian Electrical Requirements and AS3000"	For clarity and to remove reference to the WA Distribution Connection Manual which is a Western Power internal document and not a written law, statutory instrument or recognised code, standard or guideline.
All services	Remove references to the retail tariff by-laws when defining residential properties, voluntary/charitable organisations	The retail tariff by-laws are not relevant for the definition of property type for network reference services.
All services	Remove the terms "compliance instruments", "compliance meter" and "compliance metering installation"	These terms are confusing and seem only to be required for making the new time of use reference services mandatory, which the ERA has not approved.

851. Western Power accepts each of these amendments and has made the necessary changes to Appendix E of the revised proposed access arrangement. However, as noted in our response to required amendment 13 Western Power will no longer provide reference services D3 and D4 and as such has not included any amendments in respect to these services.

852. We have also made several other changes to Appendix E to incorporate refinements to the reference services as a result of this revised AA4 proposal. These changes include the following:

- a new clause 1.3 to clarify the interaction of the reference services with the provision of metering services pursuant to the Metering Code and its related instruments
- a new clause 1.4 to provide further clarity in relation to the application of the eligibility criteria
- clarifying in the eligibility criteria for each reference service the metering installation and the configuration of the meter (either uni-directional or bi-directional) that is required in order for the customer to be eligible for the service. Meters may be capable of recording one way (unidirectional) and two way (bidirectional) energy data flows but may need to be reconfigured so they are capable of recording and providing such information. It is important that the meters are correctly configured before a customer is eligible for the service
- removing the bidirectional aspect of reference services A5 to A8 and their inclusion as new Reference Services C5 to C8
- amending the eligibility criteria to acknowledge that the metering installation is installed at the metering point rather than the exit or entry point. This reflects what occurs in practice (i.e. the meter is rarely installed at the entry or exit point) and what is required pursuant to the Metering Code
- making reference services A3, A4, C3 and C4 available to existing customers only. New customers may use the new D1 and D2 reference services if they require a time of use service

- including a standard metering services guide in Annexure A. See Western Power’s response in relation to required amendment 14 for further information on the purpose of this guide.
- clause 1.1 (Definitions):
  - inclusion of new definitions of ‘AA4 effective date’, ‘interval meter (unidirectional)’, ‘minimum meter’
  - separation of ‘AMI Meter’ into ‘AMI Meter (connected)’ and ‘AMI Meter (not connected)’ to distinguish between advanced meters that are connected to a communications network and able to remotely provide advanced metering functions and those which are not
  - amendment to the definition of ‘non-residential premises’ to exclude the inclusion of ‘voluntary/charitable organisations’. This amendment makes more reference services available to voluntary/charitable organisations
  - update to the definition of ‘Small Use Customer’ to reflect the latest version of Small Use Customer Code (2018 version).

853. Given the number of amendments that were made to Appendix E: Reference Services as part of our original access arrangement and the number of further amendments included as part of the Revised AA4 proposal we are providing a clean version of Appendix E: Reference Services only.

12. Pricing methods, price list and price list information

854. This section details Western Power's response to the ERA's required amendments to the price list and price list information for the AA4 period. This section covers price list and price list information in relation to the following:

- the target revenue cap and side constraint formula
- metering costs
- new time of use and demand tariffs
- excess network usage charges (ENUC)
- streetlight tariffs
- recovery of the Tariff Equalisation Contribution (TEC).

12.1 Target revenue cap and side constraint formula

ERA required amendment 16:

Western Power must amend the 2018/19 Price List and Price List Information to be consistent with the target revenue approved by the ERA in this draft decision.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

855. For reasons outlined elsewhere in this revised proposal – including our revised capital and operating expenditure forecasts, a revised WACC and other revenue adjustments – Western Power is proposing updated revenue caps for 2018/19. On this basis, we do not intend to implement the 2018/19 Price List and Price List Information consistent with the target revenue approved by the ERA.

856. We have instead updated the Price List and Price List Information with revised revenue figures consistent with the information contained in this revised AA4 proposal.

857. We also note that due to the change to the AA4 commencement date from 1 July 2018 to 1 November 2018, additional amendments have been required in the approach to the Price List. This is outlined in the Price List Information (Appendix F.4 to the access arrangement).

ERA required amendment 17:

Western Power must expand Table 16 and Table 18 in Appendix F.4 ("2018/19 Price List Information") to include transmission tariffs.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

858. Tables 16 and 18 in Appendix F.4 (2018/19 Price List Information), which was included in Western Power's October 2017 AA4 proposal, detail how Western Power's distribution reference tariffs comply with the chapter 7 of the Access Code reference tariff requirements in respect to how:

- they recover revenue between the incremental and stand-alone costs of service provision (section 7.3(b)); and
- the variable components of the tariffs recover the incremental costs (section 7.6).

859. Consistent with each of the previous access arrangements, we have not detailed the transmission reference tariffs in either of these tables.

860. Western Power's approach since the first access arrangement (explicitly in the first access arrangement and implicitly since then) has been to rely on the use of the T-price pricing algorithm to ensure the efficient allocation of revenue to customers and generators in respect to its transmission tariffs.

861. Our approach to distribution and transmission pricing is analogous to the pricing methodology in the National Electricity Rules (NER), which describes the different approaches to distribution and transmission tariffs.

862. We consider our price methodology for transmission reference tariffs, while not the same as that applied to distribution tariffs, has and continues to be compliant with the Access Code. The application of the T-price pricing algorithm ensures tariffs remain between the incremental and stand-alone costs of service provision and variable components cover incremental costs.

863. To clearly demonstrate Western Power's pricing approach is in accordance with the Access Code, a new section has been added to the revised 2018/19 Price List Information addressing the application of the T-Price in accordance with the Access Code.

ERA required amendment 18:

Western Power must amend the side constraint formula to remove the correction factor for under or over recovery of target revenue from prior periods.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

864. Western Power does not accept this amendment.

865. For the same reasons stated in response to required amendment 2 (form of price control), we do not accept the removal of the correction factor for under or over recovery of target revenue from prior periods.

866. As outlined in our response to required amendment 2, Western Power already has discretion available to it to avoid price shocks to its customers over and above the operation of the side-constraints, and has demonstrated the willingness to use that discretion in the past. As such, we consider this amendment is unnecessary.

12.2 Metering costs

ERA required amendment 19:

Western Power must amend the 2018/19 Price List and Price List Information to include tariffs for each metering service. Evidence must be provided to demonstrate the proposed charges are cost reflective.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

867. As per Western Power's response to required amendment 14 (metering reference services), Western Power does not propose to have separate metering reference services and therefore does not require separate tariffs for such services.

868. We propose an alternative solution to ensure metering services are more cost reflective. This alternative proposal means that standard metering services (which are effectively the minimum metering service) will continue to be provided and paid for through network tariffs (as they were in each previous access arrangement period) and any further metering services will be acquired by a user either as an extended metering service under the 2006 MSLA (or a replacement MSLA) or as an additional metering service through the negotiation framework under section 5.1 of the Metering Code.

869. Western Power's approach to updating the cost for extended metering services in a replacement MSLA and the cost for additional metering services will be based on the principle that Western Power will charge the incremental cost of providing that service. That is, the price will be the cost of providing the metering service, minus the cost of any part of the standard metering service (if any) that is no longer required.

12.3 New time of use and demand tariffs

ERA required amendment 20:

Western Power must demonstrate the proposed new reference tariffs meet the requirements of the Access Code including that they recover the forward looking efficient costs of providing reference services and are set between the incremental and stand-alone cost of service.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

870. Western Power accepts this amendment and has included additional commentary in the Price List Information (Appendix F.4 to the access arrangement) to demonstrate how the tariffs for the proposed new reference tariffs (C5, C6, C7, C8, D1 and D2) meet the requirements of the Access Code.

871. We highlight that as there are currently no customers on these new reference services, the demonstration is not as straight forward as it is for existing services being carried forward into the AA4 period. As such, we have approached the task on the basis that the tariffs are set to recover the same average revenue per customer as tariffs for the most equivalent reference service.

12.4 Excess network usage charge

ERA required amendment 21:

Western Power must provide cost information to support its proposed Excess Network Usage Charges, including the factors applied for different geographical areas.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

872. Information to support Western Power's proposed Excess Network Usage Charges is set out in the following sections.

12.4.1 Charges are within range of likely costs

873. The costs Western Power may incur in circumstances where a user exceeds its contracted capacity varies depending upon a number of factors including:

- network usage and configuration at the time
- location of the connection point on the network
- number of users exceeding contracted capacity at a given time
- technical network requirements (such as those relating to reactive power) in the relevant part of the network
- time and extent to which a particular user exceeds its contracted capacity.

874. There may be times when a user exceeds its contracted capacity and Western Power does not incur substantially more costs because network use at the time is low. However, if a user significantly exceeds its contracted capacity or does so when other network users are exceeding their contracted capacity or network use is high, then the consequences for the network can be severe.

875. In these situations, the network may overload and trip-off causing undesired impacts to other network users who were operating within their contracted capacity. Financially, Western Power misses out on network charges and will incur costs to investigate the cause of the trip and re-establishing electricity supply. It will also impact Western Power's adherence to its service standard benchmarks. At worst, these situations can lead to damage to network infrastructure which in turn leads to extended outages and costly repairs. Western Power's costs in these circumstances will be considerably more than the amount recovered from the user in excess network usage charges.

876. The excess network usage charges are set between the upper and lower band of these costs and therefore, in Western Power's submission, are compliant with the requirement to reflect forward looking efficient costs.

12.4.2 Charges are applied based on constraint

877. The note to section 7.3 of the Access Code states:

> *One implication of section 7.3(b)(i) is that the charges paid by users should increase as the network becomes constrained, reflecting the increased incremental cost of service provision.*

878. In terms of the differences in Western Power's proposed excess network usage charges, the higher charges are applicable to areas of the network in which there is a greater level of constraint.

12.4.3 Charge structure aligns with Access Code objective, pricing requirements and preserves network safety/reliability

879. Clearly a significant driver in framing the use and quantum of the excess network usage charges is to provide a disincentive for network users to exceed their contractual entitlements.

880. Structuring excess network usage charges in this manner assists in ensuring network users maintain their network use within their contracted capacity limits. Having a more certain view on contracted capacity allows Western Power to more reliably plan, design and invest in its network for the benefit of all users. As such Western Power is able to more efficiently invest in and operate and use the network in line with the Access Code objective at section 2.2 of the Code.

881. Aligning excess network usage charges with the Access Code objective also allows Western Power to meet the Code pricing objectives, in particular section 7.4(b) of the Code which requires:

> *(b) the structure of reference tariffs so far as is consistent with the Code objective accommodates the reasonable requirements of users collectively;*

882. A further driver to the structure of the excess network usage charges is preserving the integrity of the network and maintaining a regime that operates reliably and fairly between all network users. This is fundamental to any network. Where a user exceeds its contracted capacity it puts into jeopardy the safety and reliability of supply to other users.

883. Section 4.30(c) of the Access Code requires the ERA to have regard to the operational and technical requirements necessary for the safe and reliable operation of the network. Excess network usage charges are a key component of achieving this aim.

884. We submit the following additional observations:

- the driver provided by the structure of the excess network usage charges to achieve the above outcomes is even more important having regard to the ERA's draft decision required amendment 42, which effectively gives Western Power no clear contractual avenue to ensure contracted capacity is not exceeded
- network charges need not be flat. They can be structured to reflect that depending on network demand capacity has a different value. Where one or more users is exceeding contracted capacity it means the demand for capacity is higher and capacity has more value. Greater demand constrains network capacity and means the cost of providing capacity is higher. Higher network charges should therefore prevail in such instances to properly reflect the greater value and cost of capacity
- the way in which the excess network charges practically operate is akin to a demand management tool. Without structuring the charges in this manner, Western Power would likely need to contract additional network control services such as for demand side management or contract additional reactive power or even augment the network at significant costs.

885. Having regard to the above, we submit that the proposed excess network usage charges accord with the Access Code.

12.5 Recovery of the Tariff Equalisation Contribution

886. In our AA4 proposal, we proposed to recover the TEC entirely from fixed components of network tariffs given the TEC is a fixed and unavoidable cost determined by State Government. Further, recovering the TEC from fixed tariff components would mean this regional subsidy is shared equally by all Western Power customers.

887. In its draft decision, the ERA considered that given the fixed nature of the TEC, recovering it via fixed charges would be consistent with section 7.6 of the Access Code[162] and that developing a fixed charge based on an equitable allocation between retailers may provide a more predictable and transparent charge for users.[163]

888. Further, the ERA highlights that the current practice of including the TEC in variable tariff components contributes to the need for adjustments to tariffs for under/over recovery of revenue for previous periods.[164] As the ERA's draft decision proposes to move Western Power from a revenue cap to a price cap, the financial implications of the increased risk of under/over recovery of TEC from variable charge components will be borne by Western Power.

889. However, as noted in correspondence to the ERA following the October 2017 AA4 submission[165], we have decided not to proceed with the proposed change to the TEC at this time. This is because experience with previous reform processes and engagement with our stakeholders has highlighted it would be prudent to allow more time to fully consider any forthcoming market reforms and the implications of these for network tariffs and the value of the TEC. We will continue to engage with our shareholder, the Department of Treasury, and other relevant agencies around these reforms and their implications for Western Power's potential to recover the cost of the TEC.

[162] Paragraph 835, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018

[163] Paragraph 838, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018

[164] Paragraph 835, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018

[165] Page 2, Western Power letter, *Update to Western Power's Access Arrangement (AA4) position on time of use network tariffs and the Tariff Equalisation Contribution* 15 December 2017.

13. Service standard benchmarks

890. This section details Western Power's response to the ERA's required amendments to the service standard benchmarks (SSBs) for the AA4 period. This section covers:

- the retention of the system minutes interrupted (SMI) SSBs
- the use of the Box-Cox transformation to determine the major event day threshold
- setting SSBs at the average of the 99th percentile of the average of the probability distributions selected according to nominated threshold criteria (with the exception of street lights[166])
- the inclusion of a measure of momentary interruptions.

13.1 System minutes interrupted

ERA required amendment 22:

Western Power must reinstate the system minutes interrupted performance measures disaggregated for radial and meshed networks as service standard benchmarks.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

891. In the AA4 proposal, Western Power removed the SMI meshed and radial measures as SSBs.

892. The ERA requires the SMI measures to be retained on the basis that Western Power did not propose *an alternative SSB that is reasonable and sufficiently detailed and complete to enable a user or applicant on the radial transmission network to determine the value represented by the reference service at the reference tariff.*[167]

893. The ERA adopts this position despite accepting in its AA3 final decision that:

- SMI has some *less than desirable statistical characteristics…. it did not consider these deficiencies to be sufficient to justify removing the measure at this time*[168]
- the combined loss of supply event frequency and average outage duration measures provide an equivalent measure of service performance to system minutes interrupted on the transmission network.[169]

894. We maintain the view that the SMI measures are statistically unsound. Transmission network events are few but the impacts can vary significantly. This results in SMI performance that can be highly volatile and difficult to manage. Any requirement to meet a compliance target in relation to these customers is likely to result in inappropriate signals for Western Power to invest. Moreover, these events are often cost prohibitive or not technically feasible to overcome.

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166 We propose to continue to set SSBs for street lights to align with the *2017 Electricity Distribution Licence Performance Reporting Handbook*.

167 Paragraph 954, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

168 Paragraph 1911, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 5 September 2012.

169 Paragraph 1915, ibid.

895. We maintain the SMI measures are unnecessary and should not be included in the suite of transmission performance measures. Transmission network performance and its impact on customers is adequately measured by the average outage duration and loss of supply event frequency (LoSEF) measures. All other transmission network service providers in Australia have had removed SMI from their regimes and are not required to report transmission performance on a regional basis.[170]

896. However, given the ERA requires the access arrangement to include SMI or a suitable new alternative SBB, and we have not been able to develop a **new** alternative SSB (noting that we consider the already-existing average outage duration and LoSEF measures are suitable alternatives), we accept the ERA's decision to retain the SMI radial and meshed SSBs for the AA4 period.

897. We have amended the access arrangement to reinstate the SMI definition and SSBs at sections 4.3.4 and 4.3.5 of the revised proposed access arrangement, respectively.

898. Western Power has applied the same methodology used to determine the SSB level for its other measures (except streetlights[171]) to calculate the proposed SSBs. This is described in section 13.3.

899. We have calculated the SSBs as:

- SMI meshed of 11.7 system minutes[172]
- SMI radial of 4.6 system minutes[173].

900. We would, however, like to reiterate the limitations of the SMI measures, particularly SMI radial, and the difficulties in establishing a new alternative measure.

901. The Technical Rules[174] requires N-0 design for the radial parts of the Western Power Network, meaning there is no redundancy in these areas. Though outages are uncommon, the lack of redundancy means customers would experience an interruption every time there is an outage on the radial network. As a result, SMI radial performance always carries the potential for volatility.

902. To improve service we would need to increase the level of redundancy in these regional areas. This would require significant investment in new transmission lines. As discussed in our AA4 proposal, unless a legislative obligation is created, this investment is unlikely to meet the requirements of the NFIT.

903. We also consider that new transmission connected customers are unlikely to be willing to pay the necessary costs to increase redundancy. The ERA notes that the implementation of constrained network access is not expected until 2022. However, even now we are seeing a reduction in the number of new customers prepared to pay the deep network connection costs that would be required to receive unconstrained access. We do not expect any new customers will pay these costs over the AA4 period and expect these customers to be connected under non-reference service contracts.

904. We appreciate the ERA's reluctance to remove a regionally-based service measure. However, we have been unable to find a more accurate, robust and meaningful measure to replace SMI with. For example, we considered segregating the (LoSEF) measures into meshed and radial but were unable to determine an appropriate LoSEF >1.0 SSB, as it would have resulted in a radial LoSEF >1.0 SSB of zero. This would have

[170] Note for example, in the Northern Territory regional reliability is reported only, without a target standard being set.

[171] We propose to continue to set SSBs for street lights to align with the *2017 Electricity Distribution Licence Performance Reporting Handbook*.

[172] This SSB is further adjusted to reflect changes to the operation of a protection scheme modification. See further discussion in section 13.3.5.2.

[173] This SSB is further adjusted to reflect the volatility of transmission network elements with limited redundancy. See further discussion in section 13.3.5.1.

[174] Chapter 12 and Appendix 6 of the Access Code provides for the Technical Rules that sets the planning and performance standards that apply to the Western Power Network.

been unworkable and would have required Western Power to invest heavily in several areas of the radial network.

905. We also highlight that the SMI measure, as it is currently designed, factors in the size of the load affected by the interruption. However, the size of the load affected has no bearing on the customers' experience and therefore is not relevant as an assessment of reliability. By considering the size of the load affected, SMI effectively discriminates against the size of the customer impacted by awarding a greater penalty for interrupting larger loads than smaller loads. We consider this discrimination is inequitable and unnecessary.

906. No measure other than SMI penalises a network service provider for the size of the lost load. LoSEF is the only other measure that considers the size of the load, and in doing-so only uses it as means of classification between two measures; LoSEF >0.1 and ≤1.0, and LoSEF >1.0. We consider the size of the interrupted load does not provide meaningful information for customers to determine network reliability – for customers, any interruption is unwelcome regardless of their size.

13.2 Major event day threshold

ERA required amendment 23:

For the purpose of monitoring the service provider's actual performance against actual service standard performance and in accordance with sections 11.2 and 11.3 of the Access Code, Western Power must amend section 4.5 of the access arrangement as follows:

4.5.3 Where Western Power has applied a Box-Cox transformation of the daily unplanned SAIDI data set to determine the major event day threshold, Western Power must:

1) Demonstrate that the natural logarithm of the data set of each unplanned SAIDI value is not normally distributed.

2) Provide the calculations that demonstrate the application of the Box-Cox transformation method to the unplanned SAIDI values.

3) Provide the data set resulting from applying the Box-Cox transformation method.

4) Demonstrate that the resulting data set is normally distributed or that the normality of the data set is improved.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

907. Western Power considers the ERA's required amendment would provide additional transparency in relation to the application of the proposed approach to determine major event days over the AA4 period.

908. We have therefore amended section 4.5.3 of the revised proposed access arrangement to include the ERA's amendments.

909. We have further amended this section to specify that we will include the required information in our annual service standard performance report provided to the ERA in accordance with Chapter 11 of the Access Code. These changes are shown with underlining.

4.5.3 Where Western Power has applied a Box-Cox transformation of the daily unplanned SAIDI data set to determine the major event day threshold, in the service standard performance report for the financial year in which the major event day threshold is used, Western Power must:

1) Demonstrate that the natural logarithm of the data set of each unplanned SAIDI value is not normally distributed.

2) Provide the calculations that demonstrate the application of the Box-Cox transformation method to the unplanned SAIDI values.

3) Provide the data set resulting from applying the Box-Cox transformation method.

4) Demonstrate that the resulting data set is normally distributed or that the normality of the data set is improved.

13.3 Setting service standard benchmarks

ERA required amendment 24:

Western Power must set service standard benchmarks at the 97.5th percentile of the single distribution of best fit for all reliability performance measures, except call centre performance and circuit availability for which the service standard benchmark must be set at the 2.5th percentile of the distribution of best fit, to the most recent five-years of performance data.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

910. In the AA4 proposal, Western Power proposed to retain the AA3 approach to determining SSBs for the AA4 period, with the following refinements to improve the statistical accuracy of the methodology:

- establishing the data series on which our SSBs are based using:
  - the five years of AA3 data to set all measures
  - a Box-Cox transformation to determine the probability of a major event day
  - distribution unplanned daily system average interruption duration index (SAIDI) when calculating the major event day threshold
- using the average of the 99th percentile (or 1st percentile for circuit availability and call centre performance) of the average distributions of best fit to set our SSBs.

911. In its draft decision, the ERA requires changes to set the SSBs:

- using the single distribution of best fit
- at the 97.5th (or 2.5th) percentile
- using the most recent five years of performance data.

912. Each of these amendments is discussed in the following sections, in addition to proposed step changes to our transmission SSBs designed to reflect our recent service performance.

13.3.1 Setting SSBs using multimodel averaging of percentile values

913. In the AA4 proposal, Western Power set SSBs using multimodel averaging of percentile values. After applying a number of statistical criteria, we averaged all distributions deemed to be appropriate.

914. The ERA requires Western Power to set SSBs using the single distribution of best fit. In its draft decision, the ERA notes its concerns relating to the use of:

- an averaging process across multiple candidate distributions
- a threshold Akaike Information Criterion (AIC) value to restrict the number of candidate distributions used in the averaging process.[175]

915. We engaged an independent statistics expert – Analytics + Data Science (A+DS) – to provide an opinion on the appropriateness of the process we used to determine our SSBs. A+DS noted that:

> *…a multimodel averaging process is desirable if it results in a more robust statistical model of the physical processes that impact service standards than can be obtained from any one single statistical model.*[176]

916. A+DS considers the specification of a single model, as required by the ERA, *is inconsistent with the standard approach used by peer reviewed studies into statistical inference*[177] and states that *Western Power's decision to base SSB/SST percentile values on a multimodel approach is consistent with the state-of-the-art practice in statistical inference*[178].

917. The ERA raises a concern that the *composition and number of distributions selected within the threshold value are likely to vary with time, introducing volatility and uncertainty*[179]. A+DS agrees that the ERA's concern is valid, but notes:

> *…the alternative solution of selecting a single statistical model will only serve to exacerbate this source of variability. A change in the composition of which models are selected will have less of an effect on the percentile estimates than shifting entirely from one single distribution to another single distribution. If intertemporal consistency is indeed a priority, then the preference should be for Western Power's averaging methodology over the selection of a single distribution.*[180]

918. The ERA is also concerned that *Western Power has not cited any peer-reviewed publication or regulatory precedent to support the proposed method of averaging percentile values of multiple distributions selected subject to nominated threshold values*[181].

919. A+DS has reviewed our use of the AIC to decide which models should be included to determine our SSBs (and SSTs). A+DS notes the use of the AIC to determine relative rankings of alternative statistical models is commonplace and cited several peer-reviewed publications, including Burham & Anderson (2002) and Symonds & Moussalli (2011), to support this approach[182]. A+DS highlights that there is no single threshold

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175 Paragraph 1014 – 1020, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
176 Page 4, *Methodology for setting the service standard benchmarks and targets - Expert Report*, Analytics + Data Science, June 2018.
177 Ibid.
178 Ibid.
179 Paragraph 1018, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
180 Page 7, *Methodology for setting the service standard benchmarks and targets - Expert Report*, Analytics + Data Science, June 2018.
181 Paragraph 1015, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
182 Page 4, *Methodology for setting the service standard benchmarks and targets - Expert Report*, Analytics + Data Science, June 2018.

value that is used as a common standard, instead the *discretion remains with the analyst*[183]. A+DS therefore considers that:

> *Western Power's methodology for selecting candidate models on which SSB/SST values are based is consistent with best practice approaches set out in peer-reviewed literature…*[184]

920. For these reasons, we consider our proposed method of deriving SSBs (and SSTs) for the AA4 period using a multimodel averaging approach is consistent with the Access Code, in particular the requirements of section 5 of the Access Code.

13.3.2 Setting SSBs to maintain service performance

921. For the AA4 period, we set SSBs and forecast expenditure with the objective to maintain the average level of service our customers have received over recent years. This approach was supported by our customers in our Customer Insights Report[185], which was submitted as part of our AA4 proposal.

922. Our objective therefore was to set the SSBs – the compliance targets or minimum service standard – at a level that we are able to meet without any SWIS-wide reliability driven investment[186]. Ideally, the SSBs would be based on the 100th (or 0th) percentile or above. If we set our SSBs at the 100th percentile or above, we would expect to meet the compliance targets, and would have minimal need to invest to improve average service levels.[187]

923. For the AA3 period, we introduced the approach to setting the SSBs based on the 97.5th (or 2.5th) percentile in the expectation that this represented a 97.5 per cent probability that each SSB would be met in a year and a 65 per cent probability of meeting all 17 SSBs in a year, assuming they are mutually exclusive. At the time, we deemed this an acceptable risk.

924. However, as it transpired during the AA3 period, we did not meet all 17 SSBs in three out of the five years.[188] We therefore no longer consider that setting the SSBs at the 97.5th (or 2.5th) percentile would reflect a **minimum** service standard. If we were to maintain the 97.5th percentile, Western Power would be at an increased risk of not meeting the SSBs over the AA4 period. This is because our SSBs are based on our rolling 12 month actual performance over the previous access arrangement period. On average our performance has improved over this sample period, thus SSBs will by definition be more stringent and harder to achieve over the AA4 period.

925. To mitigate this risk of non-compliance, our options are to set the SSBs at the 99th (or 1st) percentile as proposed, or to incur additional expenditure to increase the probability that all SSBs will be met in each year. We chose to set the SSBs at the 99th (or 1st) percentile rather than to include additional forecast expenditure in the AA4 revenue building blocks.

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183 Page 6, ibid.

184 Page 7, ibid.

185 Page 34, *Access Arrangement Information for the period 1 July 2017 to 30 June 2022, Attachment 4.1: Customer Insights Report*, Deloitte, March 2016.

186 We did, however, include reliability driven investment targeting specific areas of the network such as Kalbarri, and adjusted our SSTs for the estimated the impact on average reliability.

187 Setting SSBs at the 100th (or 0th) percentile would not guarantee that Western Power would always meet the SSB. In order to remove all incentive for Western Power to invest to improve service, the SSB would need to be set above this level to account for the absolute worst service performance outcome.

188 We did not meet the Rural Long SAIFI SSB in 2012/13 and 2013/14, and did not meet the Average Outage Duration SSB in 2015/16.

926. The ERA's technical consultant (GHD) recognises the trade-off between setting the SSBs based on the 99th (or 1st) percentile rather than the 97.5th (or 2.5th) percentile, and additional expenditure. GHD states:

> *In establishing the targets and benchmarks for AA4, Western Power has stated that its intention is to maintain performance from AA3, and avoid broad network investment to improve overall performance in line with feedback from its customers. Therefore, in setting the benchmarks (i.e. minimum service levels), we are of the opinion that Western Power was conscious to set these at a level that was comparable to the SSB values used in AA3 without necessarily adopting the same percentile (2.5th or 97.5th) as was used in AA3.*
>
> *Adopting the 2.5th or 97.5th percentile on the larger, "narrower" datasets would set the benchmark level relatively high and therefore* ***increase the risk that the minimum service level is not met****, consequently triggering a* ***broad investment requirement*** *as a compliance issue.*[189]
>
> [emphasis added]

927. Furthermore, GHD:

- *accepted the transmission values as proposed by Western Power as being reasonable, and consistent with the intent of maintaining minimum performance levels and minimising the risk of additional compliance expenditure requirements being imposed.*
- *[f]or the distribution service measures… accepted the values proposed by Western Power for their CBD, Urban and Rural Short networks, as these represent an improvement in, or raising of, the minimum service level compared to AA3.*[190]

928. Despite the advice from GHD, the ERA has instead required Western Power to set SSBs using the 97.5th (or 2.5th) percentile. The ERA considers the most relevant factor in setting service performance measures to be *the alignment of service standards with customer expectations*[191]. The ERA states:

> *… while customers in general have expressed satisfaction with current service levels, a small proportion of customers may be consistently receiving below-standard service. In this context, the ERA does not consider the proposal to set the service standard benchmarks at the 99th percentile, or 1st percentile for call centre performance and circuit availability, to be reasonable.*[192]

929. A+DS has considered this argument to set the SSBs at a more stringent level:

> *Critically, there is no mention in the Draft Decision that the ERA has identified a need for an improvement in the average level of service provided to customers within each benchmark. The ERA has, however, noted a preference that the level of variability in service standards experienced between customers be decreased.*[193]

930. The SSBs measure **average** levels of performance for a group of customers (for example, for distribution reliability measures this is based on feeder type – CBD, Urban, Rural Short and Rural Long). Using the 97.5th (or 2.5th) percentile rather than the 99th (or 1st) percentile will not guarantee an improvement in the level of service provided to each and every customer, including the worst-served customers. A+DS notes:

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189 Page 247, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.
190 Page 247, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.
191 Paragraph 1032, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
192 Paragraph 1042, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
193 Page 8, *Methodology for setting the service standard benchmarks and targets - Expert Report*, Analytics + Data Science, June 2018.

*While service standards will improve for all customers **on average**, those small proportion of customers identified by the ERA as receiving below-standard service **may not** observe any change in performance standards with the ERA's proposed 97.5th percentile SSB.*[194]

[emphasis added]

931. While we understand the intent of the ERA's required amendment, a change in any average measure is highly unlikely to result in an increase in service performance for our worst served customers. The reality is that the customers the ERA is likely to be referring to are those that are the most expensive to serve, and are unlikely to have any material impact on our average service performance measures.

932. In addressing the ERA's concerns about the level of service provided to worst-served customers, we note:

- that other elements of the regulatory framework, such as the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, rather than SSBs, are more likely to provide incentives to improve the level of service provided to those worst-served customers
- the Guaranteed Service Level[195] payment scheme compensates our worst-served customers by providing financial compensation for outages exceeding 12 hours
- the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* sets out minimum service standards[196] for small use customers, but these are to be achieved on a **so far as is reasonably practicable** basis
- expenditure programs specifically targeted at the worst-served customers are the most effective way to improve the level of service provided to these customers. Should the ERA require Western Power to improve service to those customers, it would need to develop an investment program to do so
- the ERA reduced our proposed distribution reliability driven capex by more than 50 per cent, which was designed to improve reliability for our worst-served customers, only allowing one significant project (the Kalbarri microgrid)
- there is a significant difference of opinion, even in the public submissions to our proposed revised access arrangement, as to whether the expenditure for improvements in service is at an appropriate level
- we are assessing and trialling more economic ways of improving service to these customers, including but not limited to microgrid solutions and standalone power systems, which may be more likely to offer solutions that meet the investment tests under the Access Code.

933. Should the ERA continue to require Western Power to set SSBs at the more stringent 97.5th (or 2.5th) percentile rather than the 99th (or 1st) percentile, we would need to increase our average performance for each SSB to ensure that all compliance targets are met. This would require significant expenditure above the level included in our proposal to introduce specific capex and opex programs to address each risk area.

934. As an example, we estimate that the costs to meet the more stringent SSB proposed by the ERA for Rural Long SAIFI would be approximately $26 million to address the shift in the SSB of two[197] events.[198] Improvements in average transmission service levels would be even more costly. This demonstrates the disproportion between cost and benefit in the ERA's required amendments.

194 Page 8, ibid.

195 This scheme is required under sections 18 and 19 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005.*

196 These requirements are under Division 2 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*.

197 2 events is calculated based on the difference between Western Power's proposed SSB for Rural Long SAIFI based on the averaging of the 99th percentile of distributions of best fit and the SSB under the ERA's draft decision using the 97.5th percentile of the single distribution of best fit.

198 The options for addressing frequency on Rural Long feeders are very limited and costly. Solutions may include covered conductor, undergrounding to prevent faults altogether or energy storage to respond instantly and island.

935. Given the short timeframe to prepare this revised proposed access arrangement, we have not had sufficient time to develop the full extent of investment programs that would be required to meet all 17 SSBs if they were set at the ERA's proposed level.

936. We also highlight that there may be limited options to mitigate the risks of non-compliance in some areas, and/or the options may be cost prohibitive to rectify.

13.3.3 Setting SSBs on the most recent five years of performance data

937. In the AA4 proposal, Western Power used the five years of historical data to 30 June 2017 to determine each of the SSBs. The five years of data for the AA3 period represents the most recent performance experienced by our customers and to which they supported maintaining average service performance.[199] Additionally, the five years of data to 30 June 2017 has been validated and published in the Service Standard Performance Report submitted to the ERA in September each financial year[200]. As such, it is logical to use this data to set the benchmarks for AA4.

938. The ERA states Western Power must set SSBs based on the *most recent five years of performance data*[201].

939. For the purposes of this response, we have assumed this statement is the ERA's confirmation to use the AA3 data, that is, the five years of data up to and including June 2017. Doing otherwise would introduce significant uncertainty as it would:

- include data from within the period, to set SSBs for the period
- include un-audited, un-approved data not yet subjected to ERA review through the annual service standard performance report
- include part-year data, which would be inconsistent with our financial year reporting obligations, our access arrangement period, and our incentive regimes (GSM and SSAM)
- require continuous updating through the remainder of the access arrangement determination process which could change SSBs significantly between the proposed revised access arrangement and the final decision, or further final decision as required
- mean that SSBs are set after the start of the AA4 period, which would not allow us to operate the network with known compliance targets.

13.3.4 Consistency with the Access Code

940. The ERA has not demonstrated that our proposed method of setting SSBs is inconsistent with the requirements of the Access Code, including the Access Code objective. We highlight there is no explicit Access Code requirement about the minimum level of service provided to customers.

941. Further, in proposing an alternative method of setting SSBs, the ERA's objective is to reduce volatility in customer experienced service performance. However, the ERA has not established that our proposal provides an inadequate level of service to the group of customers to which our SSBs apply[202].

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199 Page 34, *Access Arrangement Information for the period 1 July 2017 to 30 June 2022, Attachment 4.1: Customer Insights Report*, Deloitte, March 2016.

200 *Service Standard Performance Report for the year ended 30 June 2017*, Western Power, September 2017.

201 Required Amendment 24, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

202 An SSB is set for a reference service, which by definition is a service provided to a significant number of users or a substantial proportion of the market. An SSB is not a service standard for specific end-users, or even a class of specific end-users.

942. We contend that the ERA has merely proposed an alternative that would deliver an increase in average service performance levels, requiring a significant, arguably inefficient and imprudent level of investment.

943. In its owns words, the ERA states:

> *The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5.*[203]

944. For these reasons we do not accept the ERA's required amendment.

13.3.5 Step changes to historical levels of performance

945. Service performance measures are universally set based on historical data. However, history is not always the best predictor of the future and we often need to use other methods to adjust our forecasts for known changes or emerging issues.

946. We have identified two emerging issues that we propose the services and incentive framework must take into account:

1. no low probability, high impact events occurring over the AA3 period
2. a new system protection modification that increases the load shed due to interruptions in the Eastern Goldfields.

947. These are discussed in the following sections.

13.3.5.1 Low probability, high impact events

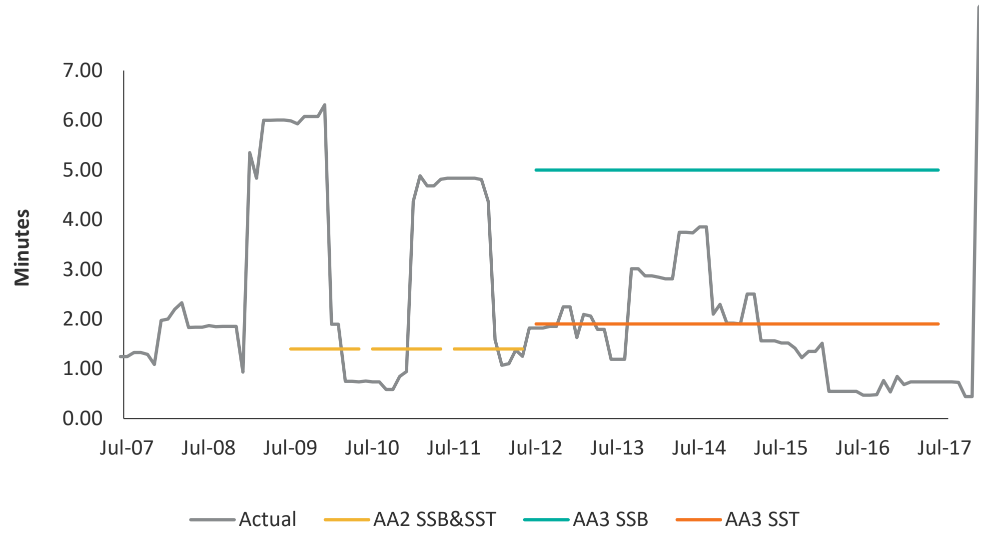
948. Western Power's obligations under the Technical Rules requires N-0 design for the radial parts of the network. Our performance is therefore heavily dependent on individual events in certain areas of the network.

949. As shown in Figure 13.1, in 2009 and 2011 we saw several low probability, high impact events affect our performance. However, performance over the five-year period on which the AA4 SSBs has been set has been relatively good, with no material events except those excluded as major event days. With a low number of critical assets, our performance in relation to transmission measures is highly dependent on these events. This is particularly the case in regional areas of the network where there is limited redundancy, and on radial lines where there is no redundancy.

950. The impact of these low probability, high impact events on transmission performance measures such as SMI radial is shown in Figure 13.1.

[203] Paragraph 22, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Figure 13.1: Historical transmission service performance, SMI radial



951. Over previous periods we have seen significant events affecting the volatility of our transmission performance (see for example high LoSEF >1.0 and SMI radial measures in 2009, and high SMI again in 2011 in Figure 13.1). Over the AA3 period – the five years on which the AA4 service standard measures are based – our performance has moderated, and there have been no low probability, high impact events. This systematically underestimates the risk of a low probability, high impact event occurring, and results in service performance measures being set at a level lower than they otherwise would.

952. For example, if we look at a one-in-ten year event, the probability of experiencing zero such events within a five-year period is 59.1 per cent and the probability of experiencing one such event within a five-year period is 32.8 per cent.

953. In 2017/18 we have already seen individual events that have significantly affected our service performance on the transmission network. For example, in December 2017 severe weather conditions caused the 132 kV line between West Kalgoorlie Terminal and Black Flag to trip. This line is compliant with the Technical Rules for N-0 design as a radial part of the network, therefore there is no redundancy available to continue to supply customers fed from this line during a line outage. The time taken to restore the fault and therefore the load at Black Flag caused an interruption of approximately 8 system minutes. Our SMI radial performance measure increased from 0.4 system minutes in November 2017 to 8.3 system minutes[204] in December 2017 due to this event alone. This is significantly greater than our current SMI radial compliance SSB target of 5.0 system minutes.

954. We do not consider investment to alleviate the impact of these type of events would be prudent or efficient. For example, we would need to build a new 132 kV line between West Kalgoorlie Terminal and Black Flag to prevent the reliability impacts from the type of event that occurred in December 2017. We estimate the cost of this to be approximately $30 million. This type of investment would be required in several areas of the radial network to mitigate our risks of non-compliance with the SSBs.

955. We consider the compliance target – the SSB – should be set at reasonable and achievable level that can be met to account for the inherent volatility in SMI radial as shown in Figure 13.1. This will ensure the incentive to maintain a minimum service level is not reduced and therefore does not diminish the power of the gain sharing mechanism (GSM) to incentivise operating expenditure efficiencies during the period. Under the Western Australian incentive mechanism framework, which links the GSM with SSB compliance,

[204] Based on comparison of 12 month rolling average performance for SMI radial as at November 2017 and December 2017.

failure to meet a minimum service standard in a financial year results in a reduction in rewards under the GSM to zero. We also highlight that, using the ERA's approach to determining the SSBs at a 97.5th percentile, our risk of non-compliance with these SSBs would be even higher and reduce the incentive to achieve operating efficiencies.

956. It is on the basis that our historical five-year period includes no low probability, high impact events that we propose a step-change in the SMI radial SSB which is particularly affected by these low probability, high impact events.

957. We have determined the quantity of these step-changes using a purely statistical method, consistent with our approach to setting SSBs. We have used the historical dataset to simulate a number of datasets in which there are multiple one-in-ten year event, and compared it to the actual performance over the five years of AA3.

958. Our proposed statistical method adjusts the SMI radial data series to include the impact of low probability, high impact events in a manner that is proportional to the probability of such an event occurring during the five-year AA4 period. Our method is outlined below.

1. We propose the low probability high impact event be modelled on the basis of a one-in-ten-year probability. The probability is based on a review of the SMI radial data for the period from August 2011 to June 2017.
2. We retain the use of a five-year sample from July 2012 to June 2017 for setting service performance benchmarks. This sample does not contain any low probability, high impact events. We sample data directly from the monthly SMI radial series for the period from August 2011 to June 2017 to generate 10,000 simulations of 71 months. Each sample contains 71 months of data, starting in August 2011, as performance metrics are based on a 12-month rolling average.[205]
3. With a probability of a one-in-ten-year event, simulations are adjusted to include the impact of a low probability, high impact event.
4. We calculated the difference between SMI radial rolling average values in two recent periods of time in which a low probability, high impact event was and was not occurring. This resulted in an approximation of a low probability, high impact event of 12.2 system minutes.
5. We replicate the approach for selecting candidate statistical distributions used in our AA4 proposal to ensure we accurately model the underlying physical processes that drive SSBs, and apply this process to the SMI radial data series. The 99th percentile values for each candidate distribution in each sample is calculated.

959. This method has resulted in a step-change in the SSBs for SMI radial of 4.8 system minutes. Table 13.1 sets out the impact of our proposed adjustment on our SSBs.

Table 13.1: SMI radial SSB step change

	SMI radial (system minutes)
Unadjusted	4.6
Adjusted	9.4
Step change	**4.8**

205 To calculate the rolling average for the current month, the previous 11 months data is required. To obtain the five year rolling average sample we therefore require 60 months of data plus the preceding 11 months of data, equating to 71 months.

960. The revised proposed SSBs are provided in section 13.3.6.

961. We have not amended the SSAM financial target levels (SSTs), as we are primarily concerned with the impact on our compliance, and consider the SSTs as proposed will provide an effective financial incentive to improve our performance where it is valued by our customers.

13.3.5.2 Step change for a new system security protection scheme

962. In response to the ERA's draft decision, which requires us to retain SMI radial and meshed SSB measures, we have further assessed the SMI data.

963. We have found that the introduction of modifications to our protection scheme in the Eastern Goldfields load area has negatively impacted the SMI meshed and LoSEF >1.0 transmission measures.

964. We continually assess the configuration and operation of our network. In 2012, we reviewed operations in the Eastern Goldfields and East Country regions and found a number of technical issues associated with the 220kV radial network due to a lack of redundancy in the area.

965. For setting the performance measures in AA4, any outages of the 220 kV line between Muja, through Merredin Terminal to Collgar Terminal or other critical non-220 kV lines, would result in:

- thermal overloading on the Merredin to Northam 132kV line
- voltage and transient stability issues in the Eastern Goldfields networks.

966. The operational risk of this issue was determined to be high. Left unresolved, these outages would result in:

- adverse public safety, reputational and financial risks associated with equipment damage to generation facilities and extended supply outages to customers in the Eastern Goldfields load area
- adverse public safety and environmental risks associated with a potential conductor failure as a result of the Merredin Terminal to Northam Terminal line overloading under the peak demand conditions
- compliance risk associated with the existing and ongoing breach of the islanding requirements under the Technical Rules.

967. We established a joint planning team of Western Power and System Management staff to assess and consider the options to resolve these issues, and determine the best option for implementation. The joint planning team determined that the most economically efficient option was to make protection modifications to an existing special protection scheme. These modifications detect any trip between Muja and Merredin Terminal on the 220 kV network and:

- trips the Merredin Terminal to Collgar Terminal 220 kV lines
- results in the loss of supply on the Collgar, Yilgarn, West Kalgoorlie Terminal 220 kV lines
- results in the loss of supply to the Yilgarn, West Kalgoorlie, Blackflag, Piccadilly and Boulder substations
- automatically operates an 'accelerated power level detection' protection scheme.

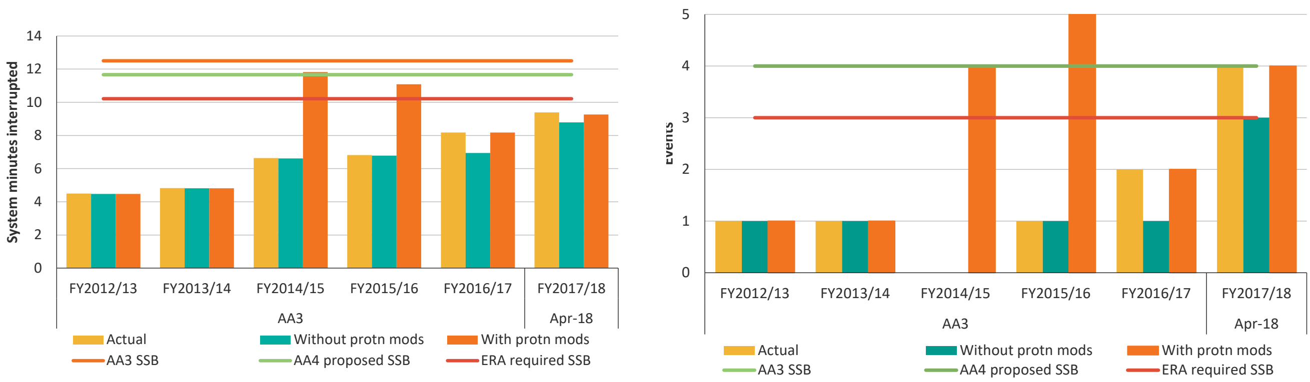
968. The modifications to the protection scheme were implemented in February 2016.

969. Practically, this change means that following an event, all load from the Muja Terminal is disconnected from the network following a trip on the Muja Terminal to Merredin Terminal line. Due to the size of the load and time to restore the 220 kV network following an interruption, all associated events will be greater than one system minute. This is because:

- the Eastern Goldfields load is approximately 100 MW. Supply restoration to this part of the network takes on average approximately 55 minutes due to its regional location. This results in an average event contributing 1.4 system minutes. This impact will further increase as new loads connect in the area
- following the protection modification, the length of line that will result in a loss of the Eastern Goldfields has increased by 50 per cent. Prior to the protection modification, a trip along the 326 kilometre line from Merredin Terminal to the West Kalgoorlie Terminal would result in loss of Eastern Goldfields. Following the protection modification, a trip along the 655 kilometre line from Muja Terminal to the West Kalgoorlie Terminal will result in loss of supply in the Eastern Goldfields. This means all lightning strikes to this part of the network that result in the loss of the Eastern Goldfields increase LoSEF >1.0 SMI events by an average of 2.6 per year.

970. To determine the impact of the protection modification, we have 'backcast' our transmission service performance over the AA3 period. Figure 13.3 shows the step-change in service performance.

Figure 13.2: Backcast of historical SMI radial and LoSEF >1.0 with protection modification



971. As shown in Figure 13.2, our actual performance has, on average, almost doubled. We have calculated that, if the protection scheme was in place over the entire AA3 period:

- there would have been an additional eight LoSEF >1.0 system minutes interrupted events since 2012/13
- we would not have met our LoSEF >1.0 SSB in 2015/16
- there would have been in an increase in SMI meshed performance of 11.3 system minutes.

972. This issue is evidenced by our actual 2017/18 performance where:

- SMI meshed has increased from 4.5 system minutes in 2012/13 to 9.4 system minutes in 2017/18[206]
- LoSEF >1.0 has increased from 2 events in 2012/13 to 4 events in 2017/18. [207]

973. We have determined the appropriate revised SMI meshed SSB and LoSEF >1.0 SSB and SST by applying the statistical methodology to setting the SSBs and SSTs based on the 5 years of historical data from 2012/13 to 2016/17, assuming the protection scheme was in place for the entire period. On the basis of this analysis, we propose the step-changes in Table 13.2.

206 Based on comparison of 12 month rolling average performance for SMI meshed as at June 2013 and as at April 2018
207 Based on comparison of 12 month rolling average performance for SMI meshed as at June 2013 and as at April 2018

Table 13.2: SMI meshed and LoSEF >1.0 system minutes step changes

Transmission	SMI meshed (system minutes) SSB	LoSEF >1.0 (events) SSB	LoSEF >1.0 (events) SST
Unadjusted	11.7	4	1
Adjusted	17.3	6	2
Step change	**5.7**	**2**	**1**

974. We highlight that, using the ERA's approach to determining the SSBs at a 97.5th percentile, our non-compliance with these SSBs would be heightened.

975. The revised proposed SSBs are provided in section 13.3.6.

13.3.6 Proposed revised service standard benchmarks

976. Each of our proposed amendments are accounted for in our proposed SSBs for the AA4 period. They are provided in Table 13.3.

Table 13.3: AA4 revised proposed service standard benchmarks

Performance measure	Unit	AA3	2017/18	From 2018/19
Distribution				
System average interruption duration index				
CBD	Minutes	39.9	39.9	37.2
Urban	Minutes	183.0	183.0	134.7
Rural short	Minutes	227.8	227.8	226.3
Rural long	Minutes	724.8	724.8	902.9
System average interruption frequency index				
CBD	Number of events	0.26	0.26	0.23
Urban	Number of events	2.12	2.12	1.33
Rural short	Number of events	2.61	2.61	2.38
Rural long	Number of events	4.51	4.51	5.90
Calls responded to in 30 seconds	Per cent	77.5	77.5	85.3
Transmission				
Circuit availability	Per cent	97.7	97.7	97.6
System minutes interrupted				
Meshed	Minutes	12.5	12.5	17.3
Radial	Minutes	5.0	5.0	9.4

Performance measure	Unit	AA3	2017/18	From 2018/19
Loss of supply event frequency				
>0.1 and ≤1.0 system minutes	Number of events	33	33	27
>1.0 system minutes	Number of events	4	4	6
Average outage duration	Minutes	886	886	1333
Street lighting				
Repair times for Perth Metropolitan area	Days	5	5	5
Repair times for major regional towns	Days	9	9	9

13.4 Momentary interruptions

ERA required amendment 25:

Western Power must set service standard benchmarks and targets for a momentary average interruptions frequency index for the fourth access arrangement period.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

13.4.1 Implementation of a service standard benchmark for momentary interruptions

977. The ERA requires Western Power to introduce a new SSB to reflect its performance with respect to momentary interruptions.

978. The ERA appears to require this amendment because:

- The AA3 final decision required Western Power to collect and report data on the average number of momentary interruptions of one minute or less per distribution network customer for each feeder category as a basis for establishing an SSB for the AA4 period.[208]
- Public submissions on the AA4 proposal supported the inclusion of a measure of momentary interruptions as an SSB.[209]
- The ERA considers the implementation of momentary average interruptions frequency index (MAIFI) as an additional SSB is required for our suite of SSBs to be *reasonable, sufficiently detailed and complete to enable a user or applicant to determine the value of the reference service at the reference tariff*[210].

979. We recognise momentary interruptions are disruptive to our customers, while noting they are less disruptive than sustained interruptions. However, we do not support the ERA's required amendment for the following reasons:

- the momentary interruption data recorded and reported during the AA3 period is incomplete, as:

208 Paragraph 1048, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
209 Paragraphs 809 and 810, ibid.
210 Paragraph 1051, ibid.

– 13 per cent of our auto reclose devices do not have telemetry
– 4 per cent of the time our communications infrastructure fails
– our existing communications infrastructure suffers from latency.

This means at least 16 per cent of momentary interruptions were not recorded. Any MAIFI SSB (or SST) will therefore be inaccurate, and could drive undesirable behaviours and/or create a perverse incentive in relation to expenditure.

- the momentary interruption data will not provide an accurate reflection of momentary interruptions experienced by our customers. This is because during the AA3 period we reported on momentary interruptions using:
  – an undocumented definition of momentary interruptions
  – highly manual processes to cleanse and validate momentary interruption data
  – undocumented, subjective and often arbitrary criteria to classify momentary interruptions (as distinct from sustained interruption events).
- there is a lack of clarity as to the appropriate definition and measure of momentary interruptions, including how it relates to the existing SAIFI measures
- the inclusion of MAIFI as an SSB does not meet the requirements as set out in the Access Code.

980. Each of these reasons are discussed in turn in the following sections.

13.4.1.1 *Incomplete momentary interruption data*

981. The timely and accurate recording and reporting on MAIFI relies on the:

- widespread installation of auto reclose devices with telemetry
- existing auto reclose devices accurately communicating a momentary interruption has occurred in the field through our communications network
- ability of the master station to correctly interpret the data received.

982. We informed the ERA during the AA3 review process that to produce accurate momentary interruptions data it would require *multi-million dollar investment.*[211] The investment in telemetry and other necessary SCADA and communications systems to produce more accurate momentary interruptions data was not approved in the ERA's AA3 final decision.

983. We committed in AA3 to continuing to reduce the number of momentary interruptions. This was achieved through prioritising the installation of telemetry on auto reclose devices on those feeders with a high number of sustained interruptions.[212] We also conducted a small trial on the utilisation of existing telemetered devices in self-healing[213] 'listening' mode to test the potential to automatically restore customers within one minute.

984. Approximately 13 per cent of the auto reclose devices in our network are not telemetered and therefore we are unable to capture momentary interruptions from those devices.

985. The ERA's AA4 draft decision includes $32.2 million to replace ageing distribution SCADA and communications assets. However, the projects included in this expenditure plan do not improve our

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211 Paragraph 1957, *ERA Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network for 1 July 2012 to 30 June 2017,* ERA, 5 September 2012.

212 This is reflected in the improvement in SAIFI on urban and rural short feeders over the last 10 years.

213 Self-healing networks refers to the use of smart network control systems and existing automation devices to respond to faults and restore customers without human operator involvement.

capability to record or report momentary interruptions. They are instead aimed at maintaining the present performance of the telecommunication portion of the distribution automation network.

986. The telemetry and other SCADA and communications systems necessary for timely recording and reporting of momentary interruptions have not been installed during the AA3 period and are not planned to be installed during the AA4 period.

987. The existing communications network was not designed to accurately capture momentary interruptions. Latency on the communications network has a direct impact on the ability to capture momentary interruptions in the field and is driven by three key issues: existing legacy assets, congestion on the network and old communications technology.

988. We also highlight that our older substations have limitations in terms of their ability to capture momentary interruption data, as they are not able to report protection device operations back to the master station when a circuit break trips. In these instances, our systems are not able to distinguish between a circuit breaker trip, which is a genuine momentary interruption event that impacts our customers, from interruptions due to testing of circuit breakers at substations, which do not impact our customers.[214]

989. Combined, the proportion of our auto reclose devices, our communication failure rate, and the latency of our existing communications network means that at least 16 per cent of momentary interruptions are not captured, and therefore not reported on.

990. As a result of the limitations of our asset population, the momentary interruption data recorded and reported are incomplete and cannot be relied upon to set any minimum service standard benchmark (or target upon which financial incentives are based).

991. We have not completed a detailed study of the program of works required to accurately and completely report on MAIFI or estimated associated expenditure. However, we maintain that if MAIFI is included as an SSB, a more widespread deployment of distribution automation and telemetry systems will be required to complete MAIFI data and allow a higher proportion of users to be able to determine the value represented by the reference service at the reference tariff.

992. Moreover, the significant cost of meeting any service target is likely to outweigh any benefits customers may receive with respect to the introduction of a new service performance measure. We consider that any SSB on MAIFI should only be introduced once the necessary distribution automation systems have been installed on an appropriate number of feeders that are reflective of the services provided to our total customer base.

993. We further caution the introduction of a MAIFI SSB (or SST) before a complete five-year data set has been established. An increase in the number of assets able to capture momentary interruptions will necessarily increase the number of momentary interruptions reported by Western Power. This will be reflected in a deterioration in our performance while MAIFI data in the calculation remains incomplete. This is problematic because it:

- is inconsistent with the requirements for an SSB, as it does not accurately reflect the difference in service performance experienced by our customers, only that reported
- creates a perverse incentive to reduce momentary interruptions to meet artificially low service standards, even where customers may not value any improvement
- may create a perverse incentive for Western Power to prioritise the installation of distribution automation systems on feeders that experience few momentary interruptions, and to not prioritise

[214] This is because we transfer our customers to another feeder for the duration of testing.

the installation of distribution automation systems on feeders that may have an adverse impact on MAIFI

- would increase the probability that Western Power is not compliant to the SSBs in any particular year which, in turn, weakens the effectiveness of the GSM.

13.4.1.2 MAIFI data not validated

994. The ERA's AA3 final decision required Western Power to collect and report data on the average number of momentary interruptions of one minute or less per distribution network customer for each feeder category as a basis for establishing SSBs for MAIFI for the AA4 period.[215]

995. We have reported the number of momentary interruptions captured in the system in our service performance report provided to the ERA annually. This measure has the aforementioned network asset related limitations as well as the following data processing and reporting limitations:

- **There was no clear definition of momentary interruptions for us to report on**. As we better understood the data captured from our network assets, we developed more robust processes and systems to categorise interruptions. This led to various changes to the definition over the AA3 period, and therefore the data captured should not be compared between years or used to set any forward-looking measures.
- **We use highly manual processes to cleanse and validate momentary interruption data.** Over the AA3 period, we captured and reported on momentary interruptions from a variety of sources, in a number of different systems. As the reporting requirement was annual, Western Power did not commit significant expenditure to systemise these processes. As a consequence, the data was not subject to the usual interrogation via robust systems and processes as our other service performance measures. Manual processes are prone to human error, and difficult to audit.
- **We use undocumented, subjective and often arbitrary criteria to classify interruptions.** Similar to the separation of loss of supply event frequency measures, there is a threshold before which an interruption is a momentary interruption and is counted as a MAIFI event, and after which is a sustained interruption and is counted as a SAIFI event. Irrespective of where this threshold is set, the determination of whether an event is deemed to be an interruption or not for the purposes of MAIFI, is highly subjective and prone to variation in interpretation between personnel interpreting the data, and over time.

996. Should the ERA require an SSB for MAIFI, we would first need to develop a customised data set that addresses the above issues, and therefore could be considered to accurately reflect our historical performance in relation to the agreed definition of MAIFI.

13.4.1.3 Lack of clarity as to the definition of MAIFI

997. As previously noted, in its AA3 final decision, the ERA did not specify the definition of momentary interruption that should be used for reporting over the AA3 period. In its AA4 draft decision, it has provided minimal further clarity, requiring us to:

> *set service standard benchmarks and targets for a momentary average interruptions frequency index for the fourth access arrangement period.*

998. There is currently considerable debate on the definition of MAIFI – whether it should be:

- for interruptions to the customer of duration of one minute or less, or three minutes or less

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[215] Paragraph 1048, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

- based on each individual momentary interruption or on a momentary interruption event which may include several attempts by the auto reclose device to restore supply (and therefore several momentary interruptions).

999. In Australia, MAIFI has commonly been defined as interruptions of less than one minute duration. This is a shorter duration than the MAIFI definitions in other countries[216].

1000. In its review of distribution reliability measures, the Australian Energy Market Commission (AEMC) recommended that the definition of MAIFI should be extended to interruptions of less than three minutes in duration. The AEMC recommended this change to:

> *…allow the distributors greater flexibility in the design of their distribution automation systems. For the majority of networks, where distribution automation systems have not yet been deployed in scale, this change would provide the potential to reduce the cost of implementing distribution automation systems. … This increased investment in distribution automation would be expected to reduce the number of sustained interruptions by automatically restoring supply to more customers, thus improving reliability performance.*[217]

1001. Consistent with this recommendation, the AER has proposed an amendment to its Service Target Performance Incentive Scheme to change the definition of MAIFI from an interruption of less than one minute in duration to an interruption of less than three minutes in duration.[218]

1002. The term 'MAIFI' is often used very loosely. While the strict definition implies that it measures each momentary interruption, there is only one jurisdiction (Victoria) which measures momentary interruption events[219]. The term '$MAIFI_e$' is now being used to distinguish momentary interruption events from individual momentary interruptions.

1003. The AEMC supports the use of $MAIFI_e$ rather than MAIFI, stating:

> *… the impact on most customers of multiple momentary interruptions within a momentary interruption event is not materially more than the impact of a single momentary interruption. That is, most of the impact of a series of momentary interruptions, within a momentary event, would be due to the first interruption. … For the purposes of incentive schemes on distributors, $MAIFI_e$ is a more preferable measure of momentary interruptions than MAIFI. This is because we considered that $MAIFI_e$ is a better measure of the impact of the interruptions on customers and because MAIFI can act as a disincentive for distributors to try to resolve supply automatically.*[220]

1004. The AER supports the continued application of the $MAIFI_e$ definition where MAIFI is currently stipulated.

1005. We highlight that the use of MAIFI, as opposed to $MAIFI_e$, would provide Western Power with a perverse incentive to not allow multiple attempts to restore supply in the event of an interruption on the network. Single auto reclose attempts would result in unnecessarily longer interruptions for customers where supply could be restored successfully following multiple auto reclose attempts[221]. This will have a direct impact on

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216 The current IEEE standard defines momentary interruptions as interruptions of duration of up to five minutes and in the UK, momentary interruptions are defined as interruptions of duration of up to three minutes. Refer Page 13, *Review of Distribution Reliability Measures, Final Report*, AEMC, 5 September 2014.

217 Page 12, *Review of Distribution Reliability Measures, Final Report*, AEMC, 5 September 2014.

218 Page 25, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2, Draft*, AER, December 2017.

219 Victoria also happens to be the only jurisdiction in which there is also a financial incentive attached to MAIFI performance.

220 Pages 14-15, *Review of Distribution Reliability Measures, Final Report*, AEMC, 5 September 2014.

221 It should be noted that, despite any AMIFI measure, Western Power will continue to adjust the behaviour of the auto-reclose function during bushfire seasons and under high risk weather conditions to mitigate the possibility of starting a bushfire.

momentary interruption performance, and would be contrary to our customers' preference towards shorter duration outages even if they are more frequent[222].

1006. We acknowledge that it is not an economically efficient strategy, nor is it possible to completely eliminate all outages. However, we urge the ERA to ensure the SSBs strongly promote incentives to invest in technologies that minimise the duration of sustained outages – aligning to our customers' interests – rather than momentary outages.

1007. On this basis, we propose to report on $MAIFI_e$ as it is the most accepted industry measure. The definition we will report on is provided in section 13.4.2.

13.4.1.4 MAIFI does not meet the requirements in the Access Code for an SSB

1008. Section 5.6 of the Access Code requires that an SSB must be *reasonable, and sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.*

1009. Specifically, MAIFI does not currently meet this requirement as:

- distribution automation and telemetry systems have not been deployed at scale across our network, and therefore MAIFI data remains incomplete and not validated. As a result, the MAIFI data would not allow our users to determine the value represented by the reference service at the reference tariff.
- the MAIFI data currently recorded and reported are incomplete due to limitations in our systems, and do not provide a reliable and robust basis on which to determine any reasonable SSBs or SSTs.

13.4.2 Proposed reporting on MAIFI during the AA4 period

1010. We propose that momentary interruption data be consistently recorded and reported based on momentary interruption events (MAIFIe) during the AA4 period. We propose we continue to report momentary interruption events, based on $MAIFI_e$, within the annual Service Standard Performance Report during the AA4 period. This provides the option to apply this definition in the following access arrangement period and with five years of consistently reported data.

1011. Given the limitations of our network assets and the existing momentary interruption data, should the ERA continue to require Western Power to include MAIFI as an SSB, then it is proposed that:

- there be one SSB covering Western Power's entire network, rather than increasing the number of SSBs by four. This would minimise the impact of the data incompleteness on our overall non-compliance to the SSBs
- the SSB be based on $MAIFI_e$, rather than MAIFI. This would minimise the impact of any perverse incentive to only allow one attempt to restore supply following a transitory fault
- a step change of 10 per cent be applied to the SSB to recognise the existing data limitations of $MAIFI_e$ and not set perverse incentives to address momentary interruptions
- additional operating expenditure of $1.3 million be provided to manage the new SSB, including to improve reporting and monitoring of performance over the AA4 period
- additional capital expenditure of $13.5 million be provided to expand the telemetry system to non-telemetered sites and improve the recorded momentary interruptions over the AA4 period

[222] Page 32, *Access Arrangement Information for the period 1 July 2017 to 30 June 2022, Attachment 4.1: Customer Insights Report*, Deloitte, March 2016.

- additional capital expenditure of around $20 million to upgrade the communications network to support high speed communications and improve the capture of actual momentary interruptions over the AA4 period.

1012. Western Power proposes to report during the AA4 period using the following definition:

$$MAIFI_e = \frac{\sum Momentary\ interruption\ events}{Total\ no.of\ distribution\ customers\ served}$$

where:

Momentary interruption events means one or more momentary interruptions that occur within a continued duration of three minutes or less, provided that the successful restoration of supply after any number of momentary interruptions is taken to be the end of the momentary interruption event.

1013. The same exclusions that apply to SAIDI and SAIFI would also apply to $MAIFI_e$.

1014. Should the definition of MAIFI be changed to interruptions of three minutes or less in line with other Australian electricity network businesses, the definition of SAIDI and SAIFI will also need to be changed to exclude interruptions of three minutes or less. This will require a step change in the SSBs and SSTs to transition from one definition to the next. We propose to measure SAIDI and SAIFI during the AA4 period using both the existing and the proposed new definitions to enable the SSBs and SSTs to be robustly determined for the following access arrangement period based on the proposed new definition.

13.4.3 Inclusion of MAIFI in the SSAM

1015. In its draft decision, the ERA requires Western Power to set service standard targets (SSTs) for MAIFI[223].

1016. As discussed in section 14.5, Western Power does not accept the ERA's required amendment to remove the financial rewards and penalties from the SSAM. Accordingly, if SSTs are set for MAIFI (or more appropriately for $MAIFI_e$), then there is a possibility of financial rewards and penalties that will apply if performance against the SSTs improves or deteriorates, respectively.

1017. In the absence of robust data on which to set SSTs for $MAIFI_e$, either Western Power or our customers will earn windfall rewards if SSTs are set and the SSAM applied for $MAIFI_e$.

1018. Until there is a reasonable likelihood of a neutral financial outcome if $MAIFI_e$ is included in the SSAM and the performance level is maintained, Western Power does not support setting SST for $MAIFI_e$ or the application of SSAM.

1019. We highlight that although MAIFI or $MAIFI_e$ is reported across Australia, Victoria is the only jurisdiction in which there is a financial incentive that applies to MAIFI performance. This is because network businesses have a limited ability to manage MAIFI outcomes without an increasingly smart population of network assets.

223 Paragraph 1052, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

14. Adjustments to target revenue at next review

1020. This section details Western Power's response to the ERA's amendments to the various revenue adjustment mechanisms that will be in place during the AA4 period. This section covers:

- force majeure;
- Technical Rules;
- the investment adjustment mechanism (IAM);
- the gain sharing mechanisms (GSM);
- the service standard adjustment mechanism (SSAM); and
- the D-factor.

14.1 Force majeure

1021. The ERA recommends two amendments to the force majeure provisions for the AA4 period. Each amendment is discussed in the following sections.

14.1.1 Requirement to demonstrate efficient costs

ERA required amendment 26:

Section 7.1.1 of the proposed revised access arrangement must be amended to include a requirement for Western Power to demonstrate that the unrecovered costs are efficient costs and do not exceed the costs which would have been incurred by a service provider efficiently minimising costs.

Western Power's response:

Western Power accepts this amendment as required by the ERA.

1022. Western Power did not propose any amendments to section 7.1.1 of the access arrangement. The ERA has made a required amendment to explicitly state that it must demonstrate the unrecovered costs associated with a force majeure event do not exceed the costs that would have been incurred by a service provider efficiently minimising costs.

1023. We note section 7.1.2 of the access arrangement refers to the amount added to target revenue being subject to sections 6.6 to 6.8 of the Access Code. Specifically, section 6.8 states:

> *An amount must not be added under section 6.6 in respect of capital-related costs or non-capital cost, to the extent that they exceed the costs which would have been incurred by a service provider efficiently minimising costs.*

1024. We consider this reference is sufficient to ensure that only efficient costs may be recovered through target revenue. However, we accept that this should be demonstrated in a report for the ERA's consideration as part of an access arrangement. We have therefore made the necessary changes to Section 7.1.1 of the revised proposed access arrangement by adding a new subsection 7.1.1(d) of the access arrangement.

1025. We have amended subsection 7.1.1(d) of the access arrangement as follows:

> *7.1.1 If a force majeure event occurs which results in Western Power incurring unrecovered costs (within the meaning of the Code) during this access arrangement period then Western Power will, as part of its proposed revisions for the next access arrangement period, provide a report to the Authority setting out:*
>
> *a) a description of the nature of the force majeure event;*
>
> *b) a description of the insurance cover that Western Power had in place at the time of the force majeure event;~~ and~~*
>
> *c) the unrecovered costs borne, or an estimate of the unrecovered costs likely to be borne, by Western Power during this access arrangement period as a result of the occurrence of the force majeure event~~.~~; and*
>
> *d) a demonstration that the amount to be added to the target revenue for the next access arrangement period in respect of those unrecovered costs does not exceed the costs which would have been (or, in the case of estimated costs, would be) borne by a service provider efficiently minimising costs.*

14.1.2 Removal of example events

ERA required amendment 27:

Section 7.1.4 of the proposed revised access arrangement must be deleted.

Western Power's response:

Western Power accepts this amendment as required by the ERA.

1026. Western Power proposed to add 'government energy reforms' to the list of the types of force majeure events that may occur.

1027. The ERA has decided to reject our proposed additional example of what may constitute a force majeure event, and has required Western Power to remove section 7.1.4 in its entirety, stating:

> *the ERA considers section 7.1.4 of the access arrangement is unnecessary given the definition of "force majeure", which is the same definition used in the Access Code:*[224]

1028. We accept the ERA's required amendment and will use the process set out in section 7.1.1 of the access arrangement to recover any unforeseen costs incurred over the AA4 period.

[224] Paragraph 1080, *Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, ERA, May 2018.

14.2 Technical Rules

ERA required amendment 28:

Western Power must delete the proposed amendments to section 7.2.1 of the proposed revised access arrangement – the current wording must be retained.

Western Power's response:

Western Power accepts this amendment as required by the ERA.

1029. Western Power proposed to amend the access arrangement to clarify that it will report on each change to the Technical Rules that results in material changes to the costs incurred or savings achieved in AA4. This is because we consider that the cost of completing a full cost-benefit assessment of each non-material change to the Technical Rules as part of an access arrangement revision submission will outweigh the benefits.

1030. In proposing changes to the Technical Rules, we follow the existing governance process detailed in section 12.50 to 12.54 of the Technical Rules. Through this process, we complete a thorough assessment of the proposed amendment including its consistency with Chapter 12 and the Access Code objective. The ERA then publishes Western Power's submission and its determinations. Under section 12.54 of the Technical Rules the process also allows the ERA to undertake public consultation where a change is considered substantial.

1031. The ERA requires Western Power to continue to report on the costs and savings of all changes to the Technical Rules on the basis that *the requirement to include a report in an access arrangement proposal on the costs or savings arising from amendments during the period should be straightforward.*[225]

1032. The explanation of whether there is an impact on costs is available through the amendments process under the Technical Rules, and as such Western Power believes this satisfies the ERA's reporting requirement.

1033. While we agree reporting is straightforward, we maintain that there is little value compiling information that the ERA already has, for the specific purpose of our access arrangement. Nevertheless, we have made the required amendment to section 7.2.1 of the revised proposed access arrangement and will continue to compile this information for the ERA as part of the access arrangement process.

[225] Paragraph 1089, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

14.3 Investment adjustment mechanism

ERA required amendment 29:

Metering expenditure must be removed from the investment adjustment mechanism.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1034. In the AA4 proposal, Western Power submitted that distribution metering capex should be included in the investment adjustment mechanism (IAM). We proposed this inclusion as it would:

- ensure the deployment of advanced meters is not unduly constrained by the capex forecast. In particular, this was proposed to facilitate the roll-out of retailer-led products and services, as the forecast uptake of new metering products is uncertain and largely out of our control
- allow Western Power to return any cost savings to customers in the AA5 period. Any capex over and above the forecast, could also be recovered, and would be subject to the ERA determining that it met the new facilities investment test (NFIT) under section 6.52 of the Access Code
- ensure that customers were not financially worse off if for some reason Western Power did not deliver the program in full.[226]

1035. The ERA decided to reject our proposal, stating that *including metering expenditure in the investment adjustment mechanism is not consistent with the Code objective and does not provide appropriate incentives for efficient metering expenditure.*[227] However, the ERA has failed to provide any reasons for its draft decision.

1036. Our metering program, as with all other customer driven work, is subject to a degree of uncertainty. This uncertainty is heightened when new services are introduced such as advanced metering. The IAM is a mechanism that compares the difference between the forecast and actual new facilities investment (investment difference) over an access arrangement period, and adjusts target revenue for that difference in the next period. The IAM is designed to be financially neutral to both Western Power and customers.

1037. The inclusion of metering under the IAM will allow Western Power to accommodate this level of uncertainty. If retailer or customer-driven meter replacements are greater than our forecast, we will be able to deliver this increased volume. However, if volumes are lower than our forecast, we are able to give the money back. Under both scenarios, Western Power and its customers will be kept financially neutral under our proposed approach.

1038. The ERA accepts that:

> *Including capacity expansion and customer driven capital expenditure in the investment adjustment mechanism ensures that Western Power's target revenue is adjusted at the next access arrangement review for any forecasting error (which is outside Western Power's control).*[228]

226 This was identified by the ERA's expert technical advisor. See pages 109 and 110 of the GHD report.

227 Paragraph 1105, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

228 Paragraph 1101, ibid.

1039. We consider the inclusion of metering capex under the IAM will similarly ensure target revenue is adjusted at the next access arrangement review for any changes in forecasts that is outside our control.

1040. Should the ERA be concerned that under the IAM our meter replacement investment may not be subject to the same rigour as if it were not, we highlight that all new facilities investment is subject to an ex-post review under section 6.51A of the Access Code. This will ensure that only capex considered by the ERA to be prudent and efficient is added to the RAB and recovered from customers.

1041. The exclusion of distribution metering from the IAM could result in Western Power under-investing in metering assets compared to what would otherwise be the efficient investment level. This is because we would be unable to recover the in-period financing cost for the additional capex in the AA4 period.

1042. It is for these reasons, we consider including distribution metering in the IAM is consistent with the requirements of the IAM under section 6.15 to 6.18 of the Access Code, the Access Code objective and the requirements of Chapter 5. Our proposed approach therefore should be accepted (as per the requirements of 4.28 of the Access Code) by the ERA.

14.4 Gain sharing mechanism

1043. Under an incentive-based economic regulatory framework, Western Power has an incentive to outperform its approved expenditure allowances, as it retains the efficiency benefits for the balance of the regulatory period. These incentives are stronger at the beginning of the period than at the end, as the efficiency benefit is retained for longer.

1044. The GSM is designed to ensure the incentive to reduce operating expenditure is consistent across the period. This allows the regulator to rely on revealed actual opex when determining forecast opex for the next regulatory period.[229] The GSM provides a long term benefit to customers because service providers are incentivised to reveal lower operating expenditure, which includes efficiency gains and in-turn leads to lower reference tariffs.[230]

1045. The service standard adjustment mechanism (SSAM), which applies to Western Power under the Access Code, balances this GSM incentive by ensuring the service provider does not underspend its opex at the expense of service performance. The SSAM does this by providing financial rewards and penalties for performance above or below average performance over the past five-year period.

1046. The GSM is provided for in section 6.21 of the Access Code, which requires the GSM to:

- achieve an equitable allocation over time between users and the service provider of innovation and efficiency gains in excess of efficiency and innovation benchmarks
- be objective, transparent, easy to administer and replicable from one access arrangement to the next
- give the service provider an incentive to reduce costs or otherwise improve productivity in a way that is neutral in its effect on the timing of such initiatives (for example, a service provider should not have an artificial incentive to defer an innovation until after an access arrangement review).

1047. In the AA4 proposal, Western Power retained the GSM that was applied in the AA3 period. However, the ERA requires several amendments for the AA4 period. Each of the ERA's required amendments are discussed in the following sections.

[229] Section 2.3, Page 4, *Service Standards Adjustment Mechanism Expert Report*, ACIL Allen Consulting, June 2018.
[230] Section 2.3, Page 4, *Service Standards Adjustment Mechanism Expert Report*, ACIL Allen Consulting, June 2018.

14.4.1 Symmetrical GSM

ERA required amendment 30:

Section 7.4.8 of the proposed revised access arrangement must be deleted.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1048. Section 7.4.8 of the access arrangement currently prohibits the GSM from producing a result that would cause target revenue in the next access arrangement to reduce. This provision ensures that the GSM only provides a reward to Western Power, consistent with the intent of the Access Code.

1049. In effect, the ERA's required amendment is attempting to introduce the concept of penalties under the GSM. It is our interpretation of the Access Code that this concept is inconsistent with the Access Code provisions relating to the GSM. These inconsistencies are discussed below.

1050. Under section 6.4(a)(i) of the Access Code, one of the objectives of the price control is that Western Power has the opportunity to earn revenue that meets the forward-looking and efficient costs of providing covered services.

1051. The remaining sub-paragraphs of section 6.4(a) provide for adjustments to this base amount. One of those adjustments in sub-paragraph (ii) is:

> *plus…an amount **in excess** of the revenue referred to in section 6.4(a)(i), to the extent necessary to **reward** the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;* [emphasis added]

1052. The amount referred to is calculated by the application of the GSM. Under section 6.19(a) of the Access Code, the GSM is a mechanism which *determines an amount to be included in the target revenue….*

1053. Under section 6.21(a) of the Access Code, the GSM must have the objective of achieving an equitable allocation over time between users and the service provider of innovation and efficiency gains in excess of efficiency and innovation benchmarks. In section 6.25 of the Access Code these gains are described as an *above-benchmark surplus*.

1054. The heading to sections 6.27 and 6.26 of the Access Code is '**Determining the increase to target revenue**'. Those sections are:

> *6.27 The Authority must apply the gain sharing mechanism to determine how much (if anything) is to be **added to** the target revenue for one or more coming access arrangement periods under section 6.4(a)(ii) in order to enable the service provider to continue to share in the **benefits** of the efficiency gains or innovations which gave rise to the **surplus**.*
>
> *6.28 If the Authority makes a determination under section 6.27 to **add an amount** to the target revenue in more than one access arrangement period, that determination binds the Authority when undertaking the access arrangement review at the beginning of each such access arrangement period.*
>
> *[emphasis added]*

1055. The language of all of these provisions relates to gains in excess of (or surplus to) benchmarks, rewards and additions to target revenue. There doesn't appear to be a reading of these provisions that allows for a reduction in revenue.

1056. The reasons for the ERA's decision by reference to the Access Code are:

> *The ERA agrees making the mechanism symmetrical would be consistent with the Access Code requirements to achieve an equitable allocation of efficiencies between users and Western Power as Western Power would be subject to symmetrical rewards and penalties.*[231]

1057. However, this omits important aspects of section 6.21(a) of the Access Code (which are underlined below):

> 1058. *A gain sharing mechanism must have the objective of achieving an equitable allocation <u>over time</u> between users and the service provider of innovation and efficiency <u>gains in excess of</u> efficiency and innovation benchmarks.*

1059. The ERA applies section 6.21(a) of the Access Code as if it were directed to equity between users and Western Power in relation to any difference between actual expenditure and forecast expenditure. However, the provision is directed to equity in relation to the timing of the receipt of the benefit of efficiency gains.

1060. The ERA also has regard to the practice of the AER. However, the AER can make its equivalent scheme symmetrical because rule 6.4.3(a)(5) of the National Electricity Rules expressly authorises both revenue increments or decrements (if any) arising from the application of any efficiency benefit sharing scheme. It is precisely because the Access Code does not authorise 'decrements' that the ERA cannot make the GSM symmetrical.

1061. Assuming the Access Code allowed for the GSM to be symmetrical, the ERA's proposal to make the GSM symmetrical gives rise to fundamental problems, particularly in light of the ERA's other required amendments. For example:

- **the ERA has removed the financial rewards and penalties under the SSAM.** If the ERA retains its view that the SSAM should have no rewards or penalties attached to it, then there would be an incentive for us to allow service levels to decline (as there is no financial penalty). This incentive would be magnified if there is also a potential penalty under the GSM for overspending opex. Combined, these two adjustment mechanisms would serve to encourage a service provider to actively allow service levels to fall towards the minimum (compliance) standard in order to avoid potential penalties under the GSM
- **the ERA has not allowed our proposal for in-period approval of D-factor projects.** In the AA4 proposal we put forward a process to facilitate the ERA's approval of our non-network solutions in-period. This was on the basis that it would improve certainty that we are able to recover these costs and thereby progress with innovative non-network solutions, rather than waiting until the end of the period. If we face both compliance and financial penalties (reward foregone under the GSM) for failure to meet service standard benchmarks (SSBs), and a financial penalty for overspending opex, it heightens the incentive for us to reduce our opex to no more than would be required to meet the SSBs. This would reduce our incentive to undertake any non-network solutions in preference to capex solutions

231 Paragraph 1121, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

1062. In its draft decision, the ERA justifies its required amendment on the basis that similar incentive schemes are symmetrical, and it would result in a more equitable allocation of benefits than that proposed by Western Power.[232]

1063. We contend that the GSM put forward in our AA4 proposal is equitable. While the GSM adjustment itself is not symmetrical, the calculation of the above benchmark surplus **does** include negative amounts to reflect unsustained opex reductions. This is designed to separate true sustainable efficiencies from one-off opex underspends. These overspends offset GSM rewards in other years and therefore acts as a form of penalty.

1064. We consider the ERA's required amendment to be inconsistent with the Access Code. Even if a symmetrical GSM was allowed under the Access Code, for the reasons discussed above we do not consider its application would result in economically efficient outcomes. We therefore do not accept the ERA's required amendment.

14.4.2 Retention of benefits under the GSM

ERA required amendment 31:

The formula in section 7.4.7 of the proposed revised access arrangement must be amended so that efficiency savings are retained for four years.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1065. In the AA4 proposal Western Power proposed to maintain the retention of the above benchmark surplus for five years under the GSM. The retention of benefits for a minimum of five years is consistent with the operation of the GSM in AA3 and other opex benefit sharing incentive schemes for energy businesses in Australia.[233]

1066. The ERA requires amendments to the access arrangement to reduce the retention of GSM benefits from five years to four years. This appears[234] to be on the basis that:

- stakeholder submissions indicated that a higher proportion of our savings should be passed onto customers
- GHD considers we have not demonstrated ongoing continuous improvement in our management of opex during AA3[235].

1067. These two considerations are discussed in the following sections.

[232] Paragraphs 1120 and 1121, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[233] Under the national electricity framework, all other transmission and distribution businesses use the Efficiency Benefit Sharing Scheme (EBSS) which provides for gains to be retained for five years. Under the national gas framework, all gas network businesses in Australia use the Efficiency Carryover Mechanism which similarly provides for gains to be retained for five years. The AER considers an alternative period may be considered, if the regulatory period is varied for any reason.

[234] Paragraph 1124, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

[235] Page 258, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

14.4.2.1 Sharing benefits between Western Power and its customers

1068. The proportion of benefits shared with our customers is directly linked to the number of years we are able to retain rewards under the GSM. Consistent with the Efficiency Benefit Sharing Scheme (EBSS) under the national electricity framework, the GSM allows Western Power to retain benefits for five years.

1069. Clause 1.3.1 of the EBSS states:

> *The carryover period will be five years unless the length of the regulatory period n, or regulatory control period n+1, is not five years. If the length of regulatory period n, or regulatory control period n+1, is not five years we may determine a different carryover period length. In determining the carryover period length, we will have regard to the matters we are required to under the NEL and the NER including but not limited to:*
>
> - *the length of regulatory control periods n and n+1*
> - *the balance of incentives provided by the EBSS, capital expenditure sharing scheme and the service target performance incentive scheme.*

1070. Section 2.3.2 of the AER's Explanatory Statement on the EBSS states:

> *The incentive to reduce opex will not be continuous if the length of the carryover period is less than the length of the regulatory control period. This is because NSPs would be able to retain recurrent efficiency gains for longer if the gain is made at the start of the regulatory control period than at the end.*
>
> *The incentives that NSPs may have to capitalise expenditure are also important. If they are not balanced then NSPs may have an incentive to substitute opex with capex even if it is not efficient to so do. Ideally NSPs should be indifferent between spending a dollar of opex instead if a dollar of capex. This is consistent with the revenue and pricing principles, which require that NSPs should be provided with effective incentives to promote economic efficiency. For similar reasons it is also important the opex incentive balances the incentive to improve reliability provided by the STPIS.*[236]

1071. The AER provides the following justification behind its adoption of a five year carryover period:

- **a five-year carryover period results in a benefit-sharing ratio of approximately 30:70 between the network service provider and network users respectively**[237]

  Sharing schemes such as the EBSS and GSM are designed to provide a fair sharing of benefits between network users and network service providers. We consider that the 30:70 sharing of benefits under the proposed retention of a five year sharing period coupled with the various offsetting incentive arrangements under the IAM and SSAM meets the Access Code objective and section 6.21(a) of the Access Code which requires that the GSM:

  > *…achieve an equitable allocation over time between users and the service provider of innovation and efficiency gains in excess of efficiency and innovation benchmarks.*

[236] Page 25, Explanatory Statement, Efficiency benefit sharing scheme – electricity network service providers, November 2013, AER

[237] Page 11 and Attachment A, Explanatory Statement, Efficiency benefit sharing scheme – electricity network service providers, November 2013, AER

- **the carry-over period should align to the length of the regulatory period**[238]

  We note that the AER has not considered any shorter carryover period than five years, and in fact in its 2008 EBSS Final Decision, the AER proposed:

  > *…a carryover period of five years except where a longer regulatory control period is approved. Where this is the case, the AER would consider permitting a longer carryover period.*[239]

1072. A further important point is that the GSM counteracts the incentive for a network service provider to spend its full opex allowance in preparation for the next revenue reset. Under a top-down forecasting approach (such as the base-step-trend method), a network service provider has incentive to increase expenditure during what would be revealed as its efficient base year. The GSM offsets this incentive by providing a more powerful financial incentive to reduce opex.

1073. If the power of the GSM incentive is diminished, for example by reducing the time period over which benefits are retained, then a network service provider may in fact be given a perverse incentive to increase expenditure.

1074. We highlight that the ERA's proposed reduction in the carryover period from five to four years would result in a sharing of approximately 20:80 between Western Power and its customers. We do not consider this would result in an equitable benefit sharing scheme, or provide a sufficient incentive to balance the opposing natural incentives that would otherwise affect Western Power's operating decisions. The ERA's required amendment is likely to result in a poorly balanced incentive framework, which may result in unintended consequences, and thereby result in worse outcomes for customers.

1075. As stated by independent expert ACIL Allen an efficiency carryover mechanism such as the GSM provides an incentive for service providers to:

> *…realise efficiency gains consistently across the regulatory period, regulators are able to rely on the revealed actual costs as the basis for forecasting opex for the following regulatory period. Over the long term, the network service providers' opex will be lower as they reveal efficiency gains and consequently customers will pay less.*[240]

1076. We consider the retention of benefits for five years meets the requirements of section 6.21 of the Access Code, and the Access Code objective. A five-year retention period results in a gain sharing arrangement that:

- is consistent with good regulatory practice
- is consistent with gain sharing arrangements for all other energy network businesses with a regulatory period of five years
- provides a sufficient incentive to drive opex reductions over the period, that customers will benefit from, both over the period, and in perpetuity
- provides a sufficient incentive to ensure the revealed base year costs are not inflated.

1077. Moreover, the ERA has failed to identify how it considers our proposal to be inconsistent with the Access Code. The ERA's required amendment is merely an alternative to our proposed retention of GSM benefits for five years. As the ERA notes, under section 4.28 of the Access Code, it must approve our proposed GSM.

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238 Page 6, *Final Decision Efficiency benefit sharing scheme (NSW and ACT) – distribution,* AER, February 2008.

239 Page 5, *Final Decision, Electricity distribution network service providers; Efficiency benefit sharing scheme*, AER, June 2008.

240 Page 4, *Service Standards Adjustment Mechanism Expert Report,* ACIL Allen Consulting, June 2018.

14.4.2.2 Ongoing continuous improvement in managing opex

1078. Under the Access Code, there is a strong link between efficiency gains under the GSM and a requirement to meet minimum service levels, the service standard benchmarks (SSBs). Section 6.26 of the Access Code states:

> *An above-benchmark surplus does not exist to the extent that a service provider achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during the previous access arrangement period by failing to comply with section 11.1.*
>
> *{Note: Section 11.1 requires a service provider to maintain a service standard at least equivalent to the service standard benchmarks set out in the access arrangement or access contract.}*

1079. We highlight that the GSM adjustment ($GSMA_t$) is calculated including the following amounts:

- the above-benchmark surplus (ABS) amounts are included where they are positive and all SSBs are met
- zero where all SSBs are not met
- the above-benchmark surplus amounts where they are negative.

1080. Including negative above-benchmark surplus amounts accounts for any reduction in costs that is not sustained.

1081. Moreover, the failure to meet any SSB in a financial year results in the removal of all GSM benefits for that year. This provides a strong incentive for Western Power to meet the Access Code objective and efficiently minimise costs.

1082. The Access Code definition for efficiently minimising costs is:

> *in relation to a service provider, means the service provider incurring no more costs than would be incurred by a prudent service provider, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest sustainable cost of delivering covered services and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services.*

1083. Despite these incentive mechanisms, GHD considers we have not demonstrated ongoing continuous improvement in our management of opex during AA3[241]. We highlight that changing the benefits sharing arrangements will not address GHD's concerns. In fact, they will lower the incentive of the GSM to achieve ongoing continuous improvement by reducing the benefit received by the service provider.

1084. Nevertheless, we can demonstrate that GHD's concerns are unfounded. GHD did not conduct detailed analysis of each year of our AA3 opex. The increases in 2015/16 and 2016/17 were driven by the Business Transformation Program. With these extraordinary costs removed, we would have seen our opex reduced year-on-year as shown in Table 14.1.

241 Page 258, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, GHD, April 2018.

Table 14.1: AA3 opex with BTP costs excluded ($ million real, June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Regulated opex	530.9	510.6	481.9	511.9	456.8
Removal of BTP costs				-66.3	-55.7
Adjusted opex	**530.9**	**510.6**	**481.9**	**445.7**	**401.1**

14.4.2.3 Consistency with the Access Code

1085. The ERA has not demonstrated that our proposed retention of benefits for five years is inconsistent with the requirements of the Access Code including the Access Code objective. Further, the ERA has not established that our proposal does not provide an incentive to reduce costs; the reductions shown above demonstrate that it does.

1086. There is no explicit Access Code requirement about the strength of the incentive. The ERA has not established that our proposal is not equitable over time. We contend that the ERA has merely proposed an alternative that would deliver a greater proportion of benefits to customers in the short term, at the expense of reducing the incentive power of the GSM, thereby reducing the potential long-term benefits to customers.

1087. In its owns words, the ERA states:

> *The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5.*[242]

1088. For these reasons we do not accept the ERA's required amendment.

14.4.3 Interrelationship of GSM benefits with service standards

ERA required amendment 32:

Section 7.4.3 of the proposed revised access arrangement must be amended to specify that an adjustment, based on the proportion of service standard benchmark failures over the access arrangement period, will be made to the total above-benchmark surplus.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1089. In its draft decision, the ERA raises concerns that:

> *The current approach [to require all SSBs in any one year to be met to enact the GSM] could lead to unintended consequences. In particular, as soon as Western Power becomes aware that it has, or is likely to, fail a service standard benchmark, the incentives to achieve efficiencies for that year reduce. It is possible there may even be incentives to increase expenditure in that year in order to achieve savings in future years.*[243]

242 Paragraph 22, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
243 Paragraph 1132, ibid.

1090. The ERA's concerns about the effectiveness of the current approach appear to have been driven by comments from Perth Energy and Synergy. However, Perth Energy and Synergy appear to be merely reiterating that efficiency gains should not come at the expense of service to customers. We agree with this principle, and propose to retain the linkage of our SSBs to the GSM as it was during the AA3 period. This will ensure we do not make gains under the GSM if we do not meet the minimum service requirements, set using the rolling average historical performance over the AA3 period (2012/13 to 2016/17). Maintaining this link should address any concerns Perth Energy or Synergy may have.

1091. The ERA has developed an alternative approach to link the GSM to the achievement of our SSBs, and requires[244] us to:

- calculate the gain share for the entire period without adjustments for SSB failures
- adjust the total gain share for the access arrangement period based on the proportion of years that service standard benchmarks were not achieved.

1092. As the ERA notes, the GSM is not symmetrical in that the annual total GSM adjustment ($GSMA_t$) cannot be negative and is adjusted to zero. However, the GSM adjustment is calculated including the following amounts:

- the above-benchmark surplus amounts are included where they are positive and all SSBs are met
- zero where all SSBs are not met
- the above-benchmark surplus amounts where they are negative.

1093. By including negative above-benchmark surplus amounts, the GSM accounts for any reduction in costs that is not sustained and would offset any positive above-benchmark surpluses in future years. We consider the inclusion of negative amounts in the calculation of the GSM adjustment value adequately addresses the ERA's concerns. In a year where we do not meet all SSBs, we would not be incentivised to overspend opex.

1094. In its draft decision, the ERA has not demonstrated our proposed retention of the GSM calculation that applied in AA3 would be inconsistent with the requirements of the Access Code and the Access Code objective. The ERA has merely provided an alternative approach that it considers may resolve a perceived problem. The ERA has not sufficiently articulated:

- the problem with the proposed ABS_t and $GSMA_t$ calculations, or
- how the proposed alternative approach addresses these perceived problems.

1095. Moreover, the required amendment appears to be inconsistent with the Access Code. The above-benchmark surplus' in section 6.25 of the Access Code is determined by reference to the efficiency and innovation benchmarks. These are annual benchmarks and the above-benchmark surplus is necessarily an annual amount. Section 6.26 of the Access Code goes on to state that this *annual* amount does not exist to the extent that Western Power fails to comply with the service standards.

1096. Further, in the timeframe to respond to the ERA's draft decision, and without any direction from the ERA, we have been unable to determine how this alternative approach would be best implemented. Without due consideration from the ERA and sufficient time for us to assess how we would need to implement the ERA's required amendment, it is likely to introduce more unintended consequences than by retaining the current approach.

1097. For these reasons we do not accept the ERA's proposed amendment.

[244] Paragraph 1133, ibid.

14.4.4 Separate benchmarks for transmission and distribution

ERA required amendment 33:

Western Power must delete the following tables from the proposed revised access arrangement and include a single table with efficiency and innovation benchmarks for the total business consistent with the ERA's determination of efficient operating costs:

Table 32: Efficiency and innovation benchmarks for the transmission system

Table 33: Efficiency and innovation benchmarks for the distribution system

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1098. During the AA3 period, the GSM included a single efficiency and innovation benchmark covering both the transmission and distribution businesses. For AA4, Western Power proposed to set separate efficiency and innovation benchmarks for the transmission and distribution businesses, thereby better reflecting the operation of its business.

1099. In its draft decision, the ERA does not approve the proposed amendment on the basis that *setting separate measures will add unnecessary complexity to the mechanism and create unintended consequences and would thus be inconsistent with section 6.21 of the Access Code and the Code objective.*[245] The ERA requires Western Power to remove the separate transmission and distribution efficiency and innovation benchmark tables and replace them with a single table.

1100. We highlight that the ERA did not remove the related amendment for this split in section 7.4.2 of the access arrangement.

1101. The ERA's decision to not approve separate efficiency and innovation benchmarks for our transmission and distribution businesses is inconsistent with its approach to setting service standards. In its AA3 final decision, the ERA rejected our proposal to combine the performance measures of our transmission and distribution network businesses into network-wide SAIDI and SAIFI measures, stating that it:

> *… had significant concerns that the effect of this change would be to dilute the attribution of overall performance to distribution and transmission networks, and as a corollary, to obscure priorities for improvement.*[246]

1102. Our proposal recognised the power of incentivising improvement in service performance and efficiencies in each part of the business – transmission and distribution – as raised by the ERA.

1103. We understand that the ERA's main concern is that *[s]etting separate gain share mechanisms could lead to cost transfers between transmission and distribution to maximise rewards.*[247] The ERA further states that *the additional controls that would be needed to ensure cost transfers did not occur would add significant complexity to the mechanism.*[248] It therefore draws the conclusion that the proposed amendment would be inconsistent with section 6.21 of the Access Code.

[245] Paragraph 1142, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
[246] Paragraph 1925, ibid.
[247] Paragraph 1140, ibid.
[248] Paragraph 1141, ibid.

1104. Western Power is a government-owned business that has its own Board and accountabilities to the Minister for Energy. This structure provides little appetite or practical scope for taking commercial advantage of the GSM at the expense of customers.

1105. Moreover, Western Power's financial structure means we are subject to financial oversight by the Department of Treasury, and economic oversight by the ERA under a full regulation framework. Each of these layers of oversight requires disclosure of finances on an ex-ante and ex-post basis, including the applicable adjustments due to accounting and regulatory treatments. This comprehensive framework provides no practical scope for taking commercial advantage of the GSM at the expense of customers.

1106. We also have a cost and revenue allocation method (which has been provided to the ERA). This provides the ERA and our customers details on how we allocate costs not only between the transmission and distribution businesses, but also between regulated and un-regulated services, and reference and non-reference services.

1107. Further, our independently audited regulated financial statements and pro-forma forecast statements provide the ERA with sufficient information on our proposed allocation of costs for the purposes of correctly allocating corporate and indirect costs between the transmission and distribution businesses such that no additional controls are required.

1108. In submitting an amended access arrangement to the ERA, which includes accounting for the GSM, Western Power is obliged to comply with the AAI Guidelines. The Access Arrangement Information Guidelines require a proper allocation between distribution and transmission if the GSM is split between distribution and transmission in the access arrangement, as proposed by Western Power. In particular, under clause 4.6.4 of the AAI Guidelines:

> *Where an adjustment to target revenue is to be made under section 6.27 of the Access Code, the access arrangement information must include:*
>
> - *details of how the adjustment to target revenue has been calculated;*
> - *evidence that the benchmark and actual non-capital costs have been adjusted to ensure that a like-for-like comparison is made, and that efficiency improvements are measured appropriately; and*
> - *if relevant, evidence to show that service targets were achieved.*

1109. It is therefore clear that in addition to there being little incentive for Western Power to make cost transfers between transmission and distribution to maximise rewards, there are also sufficient controls in place to prohibit it from doing so.

1110. Given there is no need for additional controls, we submit our proposed amendments meet the Access Code objective, and the requirements of sections 5.1 and 6.21 of the Access Code (ease of administration).

1111. On this basis we do not accept the ERA's required amendment to re-aggregate the transmission and distribution efficiency and innovation benchmarks to a network-wide efficiency and innovation benchmark.

14.4.5 Setting the GSM efficiency and innovation benchmarks

ERA required amendment 34:

Western Power must amend the efficiency and innovation benchmarks to be consistent with the draft decision on operating expenditure.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1112. Western Power agrees that the efficiency and innovation benchmarks included in section 7.4.11 of the access arrangement should reflect the amount of forecast opex included in target revenue.

1113. We have therefore amended the Efficiency and innovation benchmarks (EIBs) in the revised proposed access arrangement as shown in the following tables.

Table 14.2: Transmission efficiency and innovation benchmark, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Total forecast transmission revenue cap opex	**93,997**	**84,834**	**85,082**	**87,807**	**88,115**
Adjustments:					
Superannuation costs for defined benefits schemes	-53	-53	-54	-54	-55
Energy*Safety* levy	-1,185	-1,192	-1,201	-1,210	-1,217
ERA costs (incl. licence fees and charges, standing charges, audits and specific costs)	-435	-302	-305	-307	-448
D-factor project costs	-	-	-	-	-
Unforeseen events	-	-	-	-	-
Technical Rules changes	-	-	-	-	-
Transmission efficiency and innovation benchmark	**92,324**	**83,287**	**83,522**	**86,235**	**86,396**

Table 14.3: Distribution efficiency and innovation benchmark, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Total forecast distribution revenue cap opex	**292,321**	**268,459**	**269,840**	**278,753**	**281,308**
Adjustments:					
Superannuation costs for defined benefits schemes	-146	-146	-148	-149	-150
Energy*Safety* levy	-3,245	-3,262	-3,289	-3,314	-3,332

	2017/18	2018/19	2019/20	2020/21	2021/22
ERA costs (incl. licence fees and charges, standing charges, audits and specific costs)	-1,190	-827	-834	-840	-1,226
D-factor project costs	-	-	-	-	-
Unforeseen events	-	-	-	-	-
Technical Rules changes	-	-	-	-	-
Distribution efficiency and innovation benchmark	**287,741**	**264,223**	**265,570**	**274,450**	**276,602**

1114. The proposed amendments to forecast opex are detailed in chapter 4 of this document.

14.5 Service standard adjustment mechanism

1115. Section 6.30 of the Access Code requires Western Power's access arrangement to include a service standards adjustment mechanism (SSAM). Sections 6.29 to 6.31 of the Access Code provides the following in relation to the SSAM:

> *6.29 A "service standards adjustment mechanism" is a mechanism in an access arrangement detailing how the service provider's performance during the access arrangement period against the service standard benchmarks is to be treated by the Authority at the next access arrangement review.*
>
> *6.30 An access arrangement must contain a service standards adjustment mechanism.*
>
> *6.31 A service standards adjustment mechanism must be:*
>
> *(a) sufficiently detailed and complete to enable the Authority to apply the service standards adjustment mechanism at the next access arrangement review; and*
>
> *(b) consistent with the Code objective.*

1116. The SSAM is a feature of the Access Code price control objectives. Pursuant to section 6.4(a)(vi) of the Access Code, Western Power is to have the opportunity to earn revenue for the provision of covered services that includes an:

> *amount (if any) determined under a service standards adjustment mechanism*

1117. In the AA4 proposal, we submitted that the SSAM for the AA4 period should remain largely unchanged from the SSAM that applied during AA3. We maintained the position that the SSAM is a service incentive scheme with:

- service standard targets (SSTs) set at average historical performance levels
- financial rewards and penalties for performance against the SSTs
- incentive rates set based on the value of customer reliability or a proxy for the value of service to customers based on using revenue at risk, consistent with accepted industry practice.

1118. Our proposed changes to the SSAM were simply to update the mechanism for more up-to-date information and performance data. The changes included:

- improving the statistical accuracy of the SST calculation methodology by:
  - using the most recent five years of historical data to 30 June 2017

- using the average of the 50th percentile of the average distributions of best fit

- adjusting SAIDI and SAIFI rural long SSTs to account for the improvement in service expected as a result of the Kalbarri microgrid project[249]
- using the most recent value of customer reliability estimates based on the AEMO 2014 study[250], adjusted to apply to Western Australia, to set distribution reliability incentive rates[251]
- continuing to apply the same revenue at risk percentages as AA3 for the call centre performance and transmission network measures, but updating for the latest revenue values and accounting for the removal of system minutes interrupted measures.

1119. These relatively minor changes were designed to enhance a service incentive framework that satisfied the Access Code objective during the AA4 period and had proved effective in driving service improvement at an efficient cost.

1120. However, the ERA has not accepted several of our proposed amendments, and has even gone so far as to make fundamental changes to the SSAM for the AA4 period. The ERA requires that:

- SSTs for 2017/18 should be set at the level applied during the AA3 period
- financial rewards and penalties under the SSAM should be entirely removed for the AA4 period
- SSTs must be set at the 50th percentile of the single distribution of best fit.

1121. We do not agree with the ERA's changes and submit our response to each of its required amendments in the following sections.

1122. The purpose of the SSAM is to ensure the network service provider delivers a specific level of service performance, with targets typically set at a level that reflects the value customers place on those services. It is important that the mechanism provides a powerful incentive for the network service provider to achieve the SSTs.

1123. Perhaps more significantly, the SSAM should also balance incentives under the GSM to reduce opex, by penalising the network service provider for allowing service levels to decline. The SSAM and GSM are designed to work in tandem, providing an incentive for Western Power to reduce costs, but not to do so at the expense of service quality and performance.

1124. The ERA's required amendments to the SSAM reduce the incentive power of the SSAM. This could lead to unintended consequences. For example, removing the potential for penalties for below SST performance, when combined with the incentive under the GSM to outperform opex, provides a perverse incentive for the network service provider to allow service levels to fall below the level customers value, and potentially even as far as the minimum standard (SSB).

1125. We consider the incentive power of the SSAM as it operated during the AA3 period, is critical to our business. The rewards and penalties available under the SSAM help monetise the investment versus service performance trade-off, which is an input into our business cases and helps guide our investment and operational decisions.

1126. We have therefore not implemented the ERA's required amendments to the SSAM. Our response to each of the SSAM amendments and our revised AA4 SSAM proposal is provided in the following sections.

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249 *Access Arrangement Information – Attachment 6.3 – Study into the feasibility of a microgrid at Kalbarri,* Western Power, October 2017.

250 Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

251 *Access Arrangement Information – Attachment 6.4 – Estimation of value of customer reliability for Western Power's Network,* Western Power, October 2017.

14.5.1 Application of the SSAM during 2017/18

ERA required amendment 35:

Western Power must maintain service standard targets for the 2017/18 financial year at the level applied during the AA3 period.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1127. SSTs reflect the level of service performance above which financial rewards are received and below which financial penalties apply under the SSAM. The SSTs and the financial rewards/penalties associated with them, are used to help inform efficient investment decisions in and the operation of the network.

1128. In the AA4 proposal, we highlighted that due to the delay of the commencement of the AA4 period, the SSAM should not apply to 2017/18. This is because it would be unreasonable for Western Power to earn rewards or penalties for service performance during a year in which the SSTs were not set and target revenue was undefined. It is also not appropriate to apply service performance adjustments retrospectively (i.e. setting targets with the benefit of having performance information relating to whether or not those targets will be met).

1129. We therefore calculated incentive rates for the AA4 period (to help inform investment decisions), but to make sure the SSAM remains financially neutral until the AA4 period formally commences, we did not set SSTs for 2017/18.

1130. In its draft decision, the ERA agrees with the principle that the SSAM should not apply in 2017/18. However, rather than accepting our proposal, the ERA has:

- removed the incentive rates to prevent any financial rewards and penalties
- retained the AA3 SSTs to apply in 2017/18.

1131. Put simply, while we propose that the 2017/18 SSAM has no targets but contains incentive rates. The ERA proposes that the 2017/18 SSAM has no incentive rates but contains targets.

1132. The practical outcome of the ERA's and Western Power's proposal for 2017/18, as far as it impacts customers, is the same. It appears Western Power and the ERA are attempting to achieve the same outcome for SSAM during 2017/18 in that the SSAM has no financial impact for that year. The ERA states:

> *To the extent the penalties or rewards will not be applied under the service standard adjustment mechanism during the 2017/18 financial year, the ERA considers the proposal to be consistent with the Access Code objective and approves this element of the proposal.* [252]

1133. However, the method by which the ERA proposes to achieve this financially neutral outcome is unnecessary and has much longer term implications for Western Power's investment governance process.

1134. The SSAM proposed by Western Power includes incentive rates for the AA4 period. These rates provide a value for the benefits associated with any expenditure to maintain or improve service performance.

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252 Paragraph 1183, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

1135. For distribution network measures, the SSAM incentive rates are based on the latest value that customers place on reliability based on AEMO's 2014 Value of Customer Reliability Final Report,[253] adjusted to apply to Western Australia. For transmission network and call centre measures, the SSAM incentive rates are based on transmission and distribution revenue at risk figures (respectively) as a proxy for the value that customers place on performance.

1136. Despite the fact we submit there will be no SSTs for 2017/18, which has the effect of meaning no financial rewards or penalties will be awarded for that year, it is important that the proposed AA4 incentive rates beyond 2017/18 remain because:

- the incentive rates are used by Western Power to help monetise the investment versus service performance trade-off, which is an input into our business cases and helps guide our investment (and operational) decisions
- investment decisions are made over a horizon longer than one year, so is important to have an approved value of customer reliability in place, even if that value is not being factored into any rewards/penalties for 2017/18.

1137. The incentive rates are an important component of Western Power's investment governance, therefore it is vital the ERA approves values for AA4, even if they are not going to have an effect in the first year of the period. We have updated section 7.5 of the revised proposed access arrangement to clarify that the SSAM incentive rates apply for the entire AA4 period and that no SSAM targets apply in 2017/18.

1138. As discussed, the ERA is attempting to achieve the same outcome for 2017/18 as we are, in that the SSAM has no financial impact. However, the ERA considers SSTs must apply during 2017/18. Logically, the ERA has concluded that if the SSTs must apply, then the only way to ensure the 2017/18 SSAM is financially neutral is to make the incentive rates zero.

1139. The ERA considers SST must apply during the period because:

> *Meaningful sanctions for failing to achieve minimum service standards for reference services are available at section 11.6 of the Access Code, which requires the ERA to have regard to the service standard adjustment mechanism before determining whether to impose a civil penalty for non-compliance with service standard benchmarks.*[254]

1140. Further, the ERA has determined that the SSTs that applied in AA3 should be retained because:

> *For the purpose of reporting service performance, the ERA considers the maintenance of service standard targets from the AA3 period to be consistent with the Access Code objective.*[255]

1141. We do not agree with the ERA's interpretation of the Access Code. We consider that service standard **targets** are not a prerequisite for determining penalties for breach of the service standard **benchmarks**. SSTs need not apply during 2017/18. We further consider it a pointless exercise setting such targets with the benefit of hindsight as we will have a good understanding as to whether or not we will meet the targets while they are being set.

1142. While section 11.6 of the Access Code requires the ERA to have regard to the SSAM, it does not specifically require the ERA to have regard to the SSTs in a particular year. The ERA may have regard to the incentive

253 Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

254 Paragraph 1180, ibid.

255 Paragraph 1183, ibid.

rates in the SSAM and the SSTs in other years before determining whether Western Power has complied with its service standards as required by section 11.1 of the Access Code.

1143. Therefore we submit there is no need for SSTs to be set for 2017/18 in order for the ERA to meet its reporting requirements, nor is there a need to turn off the incentive rates in order to remove financial impacts for that year.

14.5.1.1 Western Power's 2017/18 SSAM proposal is consistent with the Access Code

1144. More importantly, the method Western Power has proposed for SSAM in 2017/18 is consistent with the requirements of the Access Code, and therefore can and must be accepted by the ERA.

1145. Section 6.30 of the Access Code requires that an access arrangement must contain a service standards adjustment mechanism. Section 6.31 of the Access Code requires a service standard adjustment mechanism to be:

> *(a) Sufficiently detailed and complete to enable the Authority to apply the service standards adjustment mechanism at the next access arrangement review; and*
>
> *(b) Consistent with the Code objective*

1146. Our AA4 proposal meets sections 6.30 and 6.31 of the Access Code as it includes a SSAM and the SSAM is sufficiently detailed and complete to enable the ERA to apply it at the next access arrangement review.

1147. Further, the Access Code objective is to:

> *…promote the economically efficient investment in and operation of and use of electricity networks and services of networks in Western Australia.*

1148. As discussed, the SSAM proposed by Western Power includes incentive rates based on the latest assessments of the value that customers place on reliability, and that these incentive rates are used to inform efficient investment in and operation of the Western Power Network.

1149. As such, Western Power's proposal is consistent with the Access Code objective.

1150. Finally, the ERA states in its draft decision:

> *If the ERA considers the Access Code objective and requirements of chapter 5 are satisfied it must approve the access arrangement. The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5.*[256]

1151. The ERA has identified an alternative approach to our proposal to not determine SSTs for 2017/18, but has not demonstrated that our proposed amendment would be inconsistent with the Access Code objective or is non-compliant with the requirements under chapter 5 of the Access Code. Contrarily, we have demonstrated that our 2017/18 SSAM proposal does meet the requirements of the Access Code and therefore can (and should) be accepted by the ERA.

1152. We therefore do not accept the ERA's required amendments and maintain that SSTs need not be provided for the 2017/18 financial year.

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256 Paragraph 22, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

14.5.2 Removal of financial rewards and penalties from the SSAM

ERA required amendment 36:

Western Power must remove the financial penalties and rewards from the service standard adjustment mechanism.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

1153. In the AA4 proposal, Western Power submitted that the SSAM for the AA4 period should remain largely unchanged from the SSAM that applied in the AA3 period, in that the SSAM is:

- a financial incentive mechanism based on SSTs set at average historical performance levels
- carries financial rewards and penalties for performance against the SSTs
- contains incentive rates set based on the value of customer reliability or a proxy for the value of customer reliability using revenue at risk consistent with accepted industry practice.

1154. In its draft decision, the ERA proposes to remove financial rewards and penalties from the SSAM. It has done this *to eliminate the risk of customers being exposed to increasing costs without commensurate improvements in service performance.*[257]

1155. The ERA submits that the Access Code objective would still be satisfied despite the removal of rewards and penalties. It considers that:

> *… the continued reporting of actual performance against service standard benchmarks and service standard targets, and the incentive structure implicit within the gain sharing mechanism to be sufficient and consistent with the Code objective of promoting efficient investment in, and use and operation of, networks and services of networks in Western Australia.*[258]

1156. The ERA's proposed amendment fundamentally changes the operation of the SSAM. We do not accept the ERA's position to remove the financial rewards and penalties from the service incentive mechanism. The ERA's required amendment:

- is not consistent with the Access Code requirements for the SSAM and the Access Code objective
- is not consistent with the purpose of the SSAM, which is to offset the incentives for the network service provider to underspend relative to its opex forecast by allowing performance to deteriorate
- provides a perverse incentive for Western Power to allow performance to deteriorate during the AA4 period despite customers paying for the improvements in performance delivered during the AA3 period
- removes the incentive for Western Power to undertake economically efficient investment to improve the level of performance on a timely basis during the AA4 period
- removes the incentive rates, which are an important consideration in Western Power's investment governance and operational decision making process.

257 Paragraph 1195, ibid.
258 Paragraph 1196, ibid.

1157. Commentary on the ERA's draft decision as well as the effective operation of the SSAM, is provided in the following sections.

14.5.2.1 The ERA's required amendment is inconsistent with SSAM requirements

1158. We submit that the SSAM requires a financial adjustment.

1159. We note that in its draft decision on the access arrangement for the AA1 period, the ERA stated that the SSAM does not require a financial incentive.[259] However, we consider the conclusion in the AA1 draft decision was, and was subsequently proven to be mistaken (given the ERA determined financial incentives were required during AA2 and AA3). It is apparent from the Access Code that a financial penalty or reward is the 'adjustment' component of the service standards adjustment mechanism.

1160. Section 6.4 of the Access Code provides for *the service provider an opportunity to earn revenue ("target revenue")* and that this is derived by adding to an 'amount' that meets forward looking costs and certain other 'amounts'. An amount is a quantity. In this case it is a quantity of target revenue, which is a financial amount. Under section 6.4(a)(vi) of the Access Code, one 'amount' added to target revenue is an amount determined under sections 6.29 to 6.32 of the Access Code (that is, the amount determined under the SSAM).

1161. We agree that when read in isolation, sections 6.29 to 6.32 of the Access Code do not expressly require that the adjustment in the SSAM be a financial adjustment. However, these sections cannot be read in isolation. They must be read in the context in which the SSAM is used.

1162. Importantly, a SSAM that contains financial incentive rates satisfies the requirements of the Access Code. The purpose of sections 6.29 to 6.32 of the Access Code is to determine the amount necessary to give operation to section 6.4(a)(vi) of the Access Code. Section 6.4(a)(vi) requires sections 6.29 to 6.32 of the Access Code to authorise a mechanism that produces an amount to be added to target revenue. This is what our proposed SSAM does.

1163. In contrast, the ERA's draft decision has the effect that there is no SSAM at all because the core characteristic of the SSAM – an adjustment to give operation to section 6.4(a)(vi) of the Access Code – is missing. This is contrary to section 6.30 of the Access Code. It has the effect of deleting section 6.4(a)(vi) of the Access Code. Section 6.4(a)(vi) of the Access Code includes in parentheses '(if any)' after the word 'amount'. However, this does not authorise the removal of the mechanism designed to produce an amount; it merely recognises that there may be a set of circumstances where that mechanism may produce no amount requiring adjustment.

1164. We also observe the different treatment of the investment adjustment mechanism (IAM) and the SSAM. Sections 6.15 to 6.18 of the Access Code share the same basic structure as sections 6.29 to 6.32 of the Access Code. However, section 6.16(b) of the Access Code expressly recognises that the IAM may not produce an adjustment to target revenue. If it had been intended for the SSAM to similarly operate, section 6.29 to 6.32 of the Access Code would have included a similar provision. That there is no provision authorising the SSAM not to produce an adjustment to target revenue is a powerful indication that it must.

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[259] Paragraphs 371 - 373, *Draft Decision on the Western Power Networks Proposed Access Arrangement for the South West Interconnected Network*, ERA, 2006.

14.5.2.2 The ERA's required amendment is inconsistent with the Access Code objective

1165. The ERA also relies on the Access Code objective to justify its changes to the SSAM. The ERA considers that removing penalties and rewards would remove the inefficiencies that arise from *increasing costs without commensurate improvements in service performance*.[260]

1166. In its expert report (provided at attachment 14.1), ACIL Allen identifies that the ERA's removal of incentive rates under the SSAM would result in Western Power being provided with an unmitigated *incentive to out-perform its expenditure forecasts and allow service performance to deteriorate to a level that is no worse than the SSB.*[261] ACIL Allen highlights that the ERA's proposed approach would lead to an outcome that is inconsistent with the Access Code objective, as without financial rewards and penalties under the SSAM, Western Power would have:

> *no incentive to improve performance, even where it is economically efficient to do so.*[262]

1167. On whether the ERA's proposed amendments to the SSAM meet the requirements of the Access Code, ACIL Allen states:

> *The removal of rewards and penalties from the SSAM does not provide an incentive for Western Power to invest in, and operate and use, the Western Power network in an economically efficient manner. It is my opinion that the removal of rewards and penalties from the SSAM is therefore not consistent with the Code objective.* [263]

1168. We therefore submit that the Access Code objective offers no support for the ERA's draft decision on the SSAM.

14.5.2.3 The purpose of the SSAM

1169. To determine whether the form of the SSAM proposed for the AA4 period is appropriate, it is important to consider the purpose of the SSAM.

1170. Western Power is regulated under an incentive-based economic regulatory framework. Under this framework, a regulated business has an incentive to outperform its expenditure forecasts and improve its profitability. Recognising the trade-off between expenditure and service, economic regulators commonly provide for some form of service incentive scheme, similar to the SSAM, to offset this incentive to underspend opex at the expense of service performance. The service incentive schemes provide an incentive to maintain performance and to improve performance where the benefits to do so exceed the costs.

1171. Within the framework of the Access Code, the GSM ensures the incentive to outperform the opex forecast is consistent across the access arrangement period. Any rewards that are paid under the GSM for efficiency benefits are offset by penalties under the SSAM if the opex reduction results in a deterioration in performance. This ensures any opex reductions are genuine efficiencies, whereby the same or a greater level of performance is achieved for less cost, rather than mere underspends.

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260 Paragraph 1195, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
261 Page 25, *Service Standards Adjustment Mechanism Expert Report*, ACIL Allen Consulting, June 2018.
262 Page 26, ibid.
263 Page 26, ibid.

1172. In its AA3 final decision, the ERA recognised that the Access Code provides little guidance on the operation of a SSAM but stated that:

> *… consistency with the Code objective **requires** that the mechanism **provides incentives** for a service provider to incur costs efficiently to achieve, and potentially improve on, service standards benchmarks established for the access arrangement period, that provide equal or greater benefits to customers.*[264]
>
> [emphasis added]

1173. Furthermore, in the same decision, the ERA noted that:

- Western Power is unlikely to invest in service improvements that deliver a net loss[265]
- any capital investments in service improvements must be efficient to meet the NFIT[266]
- the SSAM provides reasonable incentives for Western Power to undertake projects to improve services, while retaining an acceptable proportion of the benefits for customers[267].

1174. The ERA appears to be concerned that:

- Western Power has accumulated $255 million of the rewards that were available to it for meeting the SSTs under the SSAM during the AA3 period[268]
- Western Power reached the reward cap for distribution and transmission networks in two consecutive years[269]
- Western Power's customers have a preference to maintain the current level of service performance[270]
- the SSAM has not been designed to achieve a neutral outcome overall, as it considers was the intent.[271]

1175. Notwithstanding these concerns, the ERA notes that customers are receiving an improved level of service, and that this is reflected in the more stringent SSTs proposed by Western Power for the AA4 period.[272]

1176. The SSAM has operated effectively during the AA3 period. Customers are now receiving an improved level of service and Western Power is being rewarded as it would if it were operating in a competitive market. Notably, though Western Power is earning a $255 million reward, the business has also reduced its total expenditure (capex and opex) by almost $1 billion compared to the AA3 forecast. As a result, customers are receiving a better overall service at a more efficient cost.

1177. Importantly, customers are only paying for the improved level of service after the improvement has been delivered. Because the incentive rates are being set based on the value that customers place on reliability, customers pay no more for these improvements than the value they place on them.

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264 Paragraph 2140, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
265 Paragraph 2169, ibid.
266 Paragraph 2170, ibid.
267 Paragraph 2180, ibid.
268 Paragraph 1190, ibid.
269 Paragraph 1190, ibid.
270 Paragraph 1192, ibid.
271 Paragraph 1177, ibid.
272 Paragraph 1161, ibid.

1178. The SSAM would only have delivered a neutral outcome in the AA3 period, as the ERA appears to have expected, if there had been no improvement in the level of service.

1179. Further, the ERA's concern is that:

> *To eliminate the risk of customers being exposed to increasing costs without commensurate improvements in service performance, the ERA considers the Code objective is satisfied with the removal of penalties and rewards under the SSAM for the AA4 period*[273]

1180. This statement seems to misunderstand the purpose of the SSAM. Western Power is incentivised to improve service only where it is valued by customers. Therefore, customers will only be exposed to increasing costs if service is improved in line with the value to customers. Likewise, if the value to customers is to maintain service rather than improve service, based on the SSAM financial incentives, customers will not be exposed to increasing costs.

1181. The ERA does not appear to have any concerns with the principles and purpose of the SSAM, but appears to have concerns that the SSAM has delivered on its intent – to deliver improved levels of service where it is economically efficient to do so.

1182. We believe the SSAM has delivered on its intent over the AA3 period and that this intent is consistent with the Access Code objective. As such, we maintain that the SSAM should apply in the AA4 period as it has done during AA3.

14.5.2.4 Risk of maintaining performance to customers without a SSAM financial incentive scheme

1183. During the AA4 period, customers are benefitting from a higher level of performance than that experienced at the beginning of AA3. Western Power's investment plans for the AA4 period are designed to maintain current levels of service performance and as a result the works programs does not contain projects that specifically targets overall service improvement. While there will likely be a combination of rewards and penalties against individual targets, we forecast that the reliability-driven investment program for the AA4 period will return an overall neutral SSAM. The SSAM targets and incentive rates are designed to account for this.

1184. However, if there are no financial rewards or penalties associated with the SSAM, Western Power has an incentive to underspend and allow performance to deteriorate to the level of the SSBs. ACIL Allen notes that in the absence of a financial service incentive scheme *…the incentive to out-perform opex forecasts is not balanced by an incentive to maintain service levels.*.[274]

1185. This is particularly the case where performance levels have been delivered during the AA3 period through higher levels of opex. For example, Western Power has delivered the current performance levels through having more crews available when poor weather is expected and by paying crews overtime to ensure more timely restoration of supply. These performance levels are unlikely to be sustained if Western Power operated under an incentive regime that only provides an incentive to outperform opex.

1186. The GSM and SSAM need to operate together, with the GSM operating expenditure incentive mechanism to reduce costs, but not at the expense of service performance. ACIL Allen considers:

> *The network service provider could spend less on opex by not having sufficient crews available to restore supply on a timely basis so that service performance is not maintained.*

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273 Paragraph 1194, ibid.

274 Page 5, *Service Standards Adjustment Mechanism Expert Report*, ACIL Allen Consulting, June 2018.

If a network service provider spends less opex and service performance is not maintained, they would be rewarded under the efficiency carryover mechanism for that out-performance. The service incentive scheme provides a penalty to the network service provider if service performance is not maintained.[275]

1187. Removing the incentive rates removes the equilibrium between the GSM and SSAM.

14.5.2.5 Incentive rates are set at industry practice levels

1188. Economically efficient investment is incentivised through the SSAM's incentive rates. If the incentive rates are higher than the value customers place on improvements in performance, then the SSAM will incentivise more investment than is economically efficient. If the incentive rates are lower than the value that customers place on improvements in performance, then the SSAM will not incentivise investments that are economically efficient.

1189. The incentive rates that were proposed by Western Power for the AA4 period are based on accepted industry practice, using the latest information available on the level of performance valued by customers. Accordingly, the proposed incentive rates will incentivise economically efficient investment, consistent with the Access Code objective.

1190. The incentive rates have been updated based on the revised SSTs and revenue. The revised incentive rates are set out in the following table.

Table 14.4: SSAM financial incentive rates for AA4, $ real at 30 June 2017

Performance measure	Unit	AA3		AA4 proposed	
		Reward	Penalty	Reward	Penalty
System average interruption duration index					
CBD	Minutes	$74,774	$74,774	$26,734	$26,734
Urban	Minutes	$584,170	$584,170	$366,800	$366,800
Rural short	Minutes	$246,398	$246,398	$114,374	$114,374
Rural long	Minutes	$71,910	$71,910	$41,958	$41,958
System average interruption frequency index					
CBD	Number of events	$96,015	$96,015	$30,114	$30,114
Urban	Number of events	$605,308	$605,308	$366,867	$366,867
Rural short	Number of events	$245,338	$245,338	$117,788	$117,788
Rural long	Number of events	$112,161	$112,161	$65,982	$65,982
Calls responded to in 30 seconds	Per cent	-$45,752	-$45,299	-$41,140	-$9,540

275 Ibid.

Performance measure	Unit	AA3		AA4 proposed	
		Reward	Penalty	Reward	Penalty
Circuit availability	Per cent	-$901,021	-$450,510	-$434,953	-$193,313
Loss of supply event frequency					
>0.1 and ≤1.0 system minutes	Number of events	$40,045	$30,035	$43,495	$54,369
>1.0 system minutes	Number of events	$180,204	$180,204	$108,738	$217,477
Average outage duration	Minutes	$3,834	$2,751	$1,883	$3,000

1191. The SSAM is also subject to a cap on the maximum rewards and penalties in a year. While the cap limits the rewards and penalties paid by Western Power (and the amount paid by customers), it also has the effect of capping investment in performance improvements, even where this may be economically efficient. For example, under the Service Target Performance Incentive Scheme (STPIS)[276], AusNet Services states:

> *… a cap on revenue upside is simply penalising consumers by preventing them from receiving efficient reliability improvements as opposed to protecting them from paying windfall gains to a DNSP from random reliability improving events not related to the underlying reliability performance.*[277]

1192. During the AA3 period, Western Power reached the reward cap in two consecutive years. As a consequence, customers will pay less for these improvements in performance than the value they place on them.

1193. Western Power has proposed a cap of five per cent of distribution revenue at risk for the distribution measures. This is line with the current national guideline on the revenue at risk for distribution network service providers[278] and is less than caps that have been applied previously. For example, the Victorian electricity distributors had no cap from 2001 to 2010[279] and AusNet Services had a seven per cent cap from 2001 to 2015[280].

1194. We propose a cap of one per cent of transmission revenue at risk for the transmission measures. This is less than revenue at risk as set out in the current national guideline on the revenue at risk for transmission network service providers[281], which is 1.25 per cent on the service component.

14.5.2.6 A SSAM with appropriate incentive rates drives the right behaviour over the longer term

1195. The SSAM and equivalent mechanisms in the AER regulatory framework are designed to drive efficient behaviour over the long term.

1196. ACIL Allen has conducted a study into the service performance and resulting rewards over time within the Victorian regulatory framework.[282] The study shows that while the service incentive schemes have the effect of driving service improvements during the regulatory periods following their introduction, the opportunity for service improvement and the value customers place on service improvement diminishes

276 The AER STPIS comprises performance measures, targets for those performance measures, incentive rates, exclusions and caps.
277 Page 55, *Electricity Distribution Price Review 2011-2015, Regulatory Proposal, Public Version,* SPI Electricity Pty Ltd, November 2009.
278 Clause 2.5(a), *Electricity distribution network service providers, Service target performance incentive scheme*, AER, November 2009.
279 Page 20, Office of the Regulatory-General, *Electricity Distribution Price Determination 200105*, Volume 1: Statement of Purpose and Reasons, September 2000.
280 Page 10, *Service Standards Adjustment Mechanism Expert Report*, ACIL Allen Consulting, une 2018.
281 Clause 3.3(a), *Electricity transmission network service providers, Service target performance incentive scheme, Version 5 (corrected),* AER, October 2015.
282 Provided as Attachment 14.1.

over time. Therefore the rewards available under the schemes also reduce as service reaches an equilibrium with customers' expectations.

1197. We expect a similar trend to occur for Western Power under the SSAM, in that the opportunities to earn rewards will decrease over time. Our AA4 SSAM proposal contains more stringent targets than AA3, with smaller potential rewards. Given the lag between investment and actual service improvement, it is also worth noting that service performance during the AA4 period will be influenced by expenditure levels during AA3 that were almost $1 billion lower than forecast. As a result, we consider the likelihood of Western Power receiving $255 million of rewards in AA5 is low.

1198. ACIL Allen assessed the Victorian distribution network incentive schemes since they were introduced in 2001. A service incentive scheme is defined as having *performance measures, targets for those performance measures, incentive rates, exclusions and caps*[283].

1199. For the first service incentive scheme for the Victorian 2001-05 regulatory period, targets were set to improve reliability over the period. Expenditure forecasts were provided to meet the targets based on incentive rates based on the marginal cost of those reliability improvements.[284] This was similar to Western Power's access arrangement for the AA1 and AA2 period, where targets were set to improve reliability and expenditure was approved for targeted reliability improvement.

1200. The Victorian scheme was modified for the 2006-10 regulatory period to have targets set based on the actual performance at the time of the review. Financial rewards were paid for improvement in performance, financial penalties were paid for deterioration in performance. No expenditure was provided for reliability improvements and incentive rates were set based on the value of customer reliability (VCR) determined by VENCorp and then the AEMO.[285]

1201. In 2008, economic regulation transferred to the AER. The AER developed a service incentive scheme that set targets based on the distribution network service provider's average performance over the previous five years. Western Power's access arrangement for the AA3 period followed a similar approach, setting targets based on average performance[286] of the previous five years for transmission and call centre performance measures and three years for distribution measures.

1202. ACIL Allen graphed the service Victorian incentive scheme targets[287] from 2000 to 2020 for SAIDI and SAIFI (CBD, Urban, Rural Short and Rural Long). ACIL Allen comments that:

> *the targets reflect actual performance without the year on year volatility, albeit on a lagged basis. For example, an improvement in the target for 2011-15 to 2016-20 reflects an improvement in performance during the 2011-15 regulatory period.*[288]

1203. While service performance improved sharply in the early periods, the upward trend flattened over time. ACIL Allen considers that:

> *the trend rates are declining consistent with performance approaching the levels that are the optimum that can be achieved with the current technology and practices that can be implemented, based on the current value of customer reliability.*[289]

283 Page 9, *Service Standards Adjustment Mechanism Expert Report,* ACIL Allen Consulting, June 2018.
284 Ibid.
285 Pages 9-10, ibid.
286 Based on the 50th percentile of the monthly 12-monthly rolling average performance for the five or three years up to and including 2011/12 performance.
287 Targets were used rather than actual because some actual data was no longer publicly available.
288 Page 11, *Service Standards Adjustment Mechanism Expert Report,* ACIL Allen Consulting, June 2018.
289 Ibid.

1204. We consider that Western Power's performance under the SSAM reasonably reflects the Victorian distribution network service providers' experience, and that the current upward trend in performance improvement is similarly likely to flatten over the AA4 period and beyond.

1205. During the AA3 period, Western Power had an incentive to improve the level of service where it was economically efficient to do so. The incentive rates for the AA3 period were based on the best information available at that time on the value that customers placed on improvements in service. The latest AA4 information available indicates that the value customers place on reliability has decreased. This is consistent with the AER's incentive rates dropping in the 2015-20 regulatory period.

1206. Accordingly, the opportunity for Western Power to identify improvements in service that are economically efficient will be substantially reduced during the AA4 period. If there are financial rewards and penalties associated with the SSAM, it may even be economically efficient to allow performance to deteriorate where the costs to maintain a particular level of service are now greater than the value that customers place on that level of service. In such an event, Western Power would be penalised for this deterioration in performance, and customers would pay less during the AA5 period than they would if the SSAM has no financial rewards and penalties.

1207. ACIL Allen notes there were instances of deterioration of the targets in the Victorian framework, typically following a period of improvement. 'Urban Unplanned SAIDI' for CitiPower from the 2011-15 regulatory period to the 2016-20 regulatory period[290] and 'Rural Long Unplanned SAIFI' for United Energy from the 2006-10 regulatory period to the 2011-15 regulatory period, both saw deterioration following service improvement.[291] ACIL Allen confirms that in these instances, if service performance is not sustained then the rewards that customers pay for in one period will be returned by way of penalties in the next period.[292]

1208. Western Power has generally seen similar improving performance trend across its Urban and Rural Short SAIDI and SAIFI measures, and notes that these trends are declining. Western Power's rural long SAIDI performance has been declining and rural long SAIFI is fairly consistent over time.

1209. Given the service improvements during the AA3 period, further opportunities to identify economically efficient improvements in performance are now only likely to occur if there is an increase in the value that customers place on service improvement, or if there are technological advances that allow improvements to be delivered at a lower cost. But these economically efficient improvements in performance will only be delivered to customers if there is an incentive to do so under the SSAM.

1210. Opportunities for service performance improvement (where they are valued or economically efficient to do so) will be delivered to customers on a more timely basis if they are incentivised through the SSAM during the AA4 period rather than waiting for a regulatory reset in the AA5 period.

14.5.2.7 Western Power's proposal is consistent with the Access Code requirements

1211. During both the AA2 period[293] and AA3 period[294], the ERA approved access arrangements including a SSAM with a financial reward and penalty scheme. In the ERA's Final Decision on the access arrangement for the AA3 period it stated:

290 Page 12, ibid.
291 Page 13, ibid.
292 Page 11, *Service Standards Adjustment Mechanism Expert Report, ACIL Allen Consulting*, June 2018.
293 Section 5.24A and 5.24B, *Amended Proposed Revisions to the Access Arrangement for the South West Network owned by Western Power (for 2009/10 to 2011/12),* December 2009.
294 Section 7.5.4 to 7.5.11*, Amended proposed revisions to the Access Arrangement for the Western Power Network (for 2012/13 to 2016/17),* June 2015.

*The current access arrangement [AA2] Service Standards Adjustment Mechanism (**SSAM**) provided incentives for Western Power to maintain and improve service standard performance over time. The SSAM provides financial rewards for performance improvements relative to Service Standard Benchmarks (**SSB**), and financial penalties for under-performance relative to the SSBs. The resulting net incentive reward or penalty is carried forward to contribute to the total revenue for Western Power in the first year of the third access arrangement period.*[295]

1212. In the ERA's AA3 final decision the ERA considered the SSAM is required to provide:

...incentives for a service provider to incur costs efficiently to achieve, and potentially improve on, service standards benchmarks established for the access arrangement period, that provide equal or greater benefits to customers. These costs may be of a capital nature, such as costs of replacing network assets subject to failure, or a non-capital nature, such as costs of undertaking preventative maintenance or employing additional work crews to restore supply more quickly when an outage occurs.[296]

1213. As discussed, the SSAM proposed by Western Power for the AA4 period is broadly the same as that for AA3, but with more stringent SSTs and less scope for rewards. Therefore we consider the AA4 SSAM continues to meet the requirements of the Access Code.

1214. The incentive rates proposed for the SSAM are based on the value that customers place on service performance. That is, they provide an incentive to maintain performance where benefits do not exceed the costs and provide an incentive to improve performance only where the benefits exceed the costs. Therefore, the SSAM would result in maintaining service and improving service only where it is economically efficient to do so.

1215. The ERA has not demonstrated that our proposed SSAM would be inconsistent with the Access Code objective or is non-compliant with the requirements under Chapter 5 of the Access Code. It has proposed an alternative approach to the design of the SSAM, which we consider is inconsistent with the Access Code.

1216. The ERA has also failed to demonstrate how its alternative approach meets the Access Code objective, given it has previously stated that the Access Code objective requires the SSAM to provide financial incentives.

1217. We therefore do not accept the ERA's required amendments and maintain that the SSAM should operate during the AA4 period with financial rewards and penalties based on the revised incentive rates set out in Table 14.4.

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295 Paragraph 1240 *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, 5 September 2012.

296 Paragraph 2140, ibid.

14.5.3 Setting the service standard targets within the SSAM

ERA required amendment 37:

Western Power must set service standard targets at the 50th percentile of the single probability distribution of best fit.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1218. For the reasons provided in section 13.3.1, Western Power does not accept the ERA's required amendment to use a single probability distribution to set the SSTs. We maintain that the SSTs should be set as the **average of** the 50th percentile of **distributions** of best fit, rather than the 50th percentile of **the single distribution** of best fit.

1219. In its draft decision, the ERA's reasons for the required amendment are:

> *The ERA considers the proposed method of averaging the 50$_{th}$ percentile of probability distributions selected according to nominated threshold criteria does not satisfy the general Code objective of promoting economically efficient investment in and operation and use of networks and services of networks in Western Australia.*[297]

1220. The statistical method to use the 50th percentile of the recent five years of AA3 data (2012/13 to 2016/17) is consistent with the approach used to set the AA3 SSTs (which were based on the five financial years prior to AA3).

1221. Having SSTs set at the 50th percentile, together with retaining rewards and penalties under the SSAM, would address feedback we received from customers that they are comfortable with Western Power maintaining service at current service levels.[298] Synergy's submission also supports Western Power continuing to maintain performance at current (AA3) levels.

> *Synergy recommends the service standard targets for the AA4 period be set at a level that will maintain current performance standards.* [299]

1222. Western Power and the ERA agree on using the 50th percentile of the recent five years of AA3 data to set the SSTs.

1223. Where we do not agree is that Western Power proposes to use the average of the distributions of best fit (including a threshold criteria), whereas the ERA proposes to maintain the single distribution of best fit.

1224. As discussed in section 13.3.1, and supported by independent statistics expert Analytics + Data Science (A+DS), the average of the distributions of best fit results in a better outcome because:

- the multimodel averaging process is *consistent with the state of-the-art practice in statistical inference*[300] compared to the ERA's use of single distribution of best fit
- it results in a reduced level of volatility and variability than the single distribution of best fit approach.

297 Paragraph 1206, ibid.
298 Page 32, *Access Arrangement Information – Attachment 4.1 – Customer Insights Report*, Western Power, October 2017.
299 Paragraph 1204, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
300 Page 4, *Methodology for setting the service standard benchmarks and targets - Expert Report*, Analytics + Data Science, June 2018.

...the alternative solution of selecting a single statistical model will only serve to exacerbate this source of variability. A change in the composition of which models are selected will have less of an effect on the percentile estimates than shifting entirely from one single distribution to another single distribution. If intertemporal consistency is indeed a priority, then the preference should be for Western Power's averaging methodology over the selection of a single distribution.[301]

- the use of a threshold Akaike Information Criterion (AIC) value to restrict the number of candidate distributions *is consistent with best practice approaches set out in peer-reviewed literature...*[302].

1225. We consider our proposed method of deriving SSTs (and SSBs) for the AA4 period, using an averaging approach, is consistent with the objective and section 5 of the Access Code. On this basis:

> *The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5.*[303]

1226. As discussed in section 13.3.5.2, we have also revised our LoSEF >1.0 SST to apply a step change based on a new system protection modification that increases the load shed due to interruptions in the Eastern Goldfields.

1227. We have determined the appropriate revised LoSEF >1.0 SST by applying the statistical methodology to setting the SSBs and SSTs based on the five years of historical data from 2012/13 to 2016/17, assuming the protection scheme was in place for the entire period. On the basis of this analysis, we propose a step change to the LoSEF >1.0 system minutes SST of one event.

14.5.4 Proposed revised service standard targets

1228. Each of our proposed amendments are accounted for in our proposed SSTs for the AA4 period. They are provided in the following table.

Table 14.5: AA4 revised proposed service standard targets

Performance measure	Unit	AA3	2017/18	From 2018/19[304]
Distribution				
System average interruption duration index				
CBD	Minutes	20.3	-	17.8
Urban	Minutes	136.6	-	108.7
Rural short	Minutes	207.8	-	190.4
Rural long	Minutes	582.2	-	675.6
System average interruption frequency index				
CBD	Number of events	0.14	-	0.14
Urban	Number of events	1.36	-	1.12
Rural short	Number of events	2.27	-	2.01

301 Page 7, ibid.
302 Page 7, ibid.
303 Paragraph 22, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.
304 This assumes the revised access arrangement commences on or before 1 July 2018.

Performance measure	Unit	AA3	2017/18	From 2018/19[304]
Rural long	Number of events	4.06	-	4.67
Calls responded to in 30 seconds	Per cent	87.6	-	92.2
Transmission				
Circuit availability	Per cent	98.1	-	98.5
Loss of supply event frequency				
>0.1 and ≤1.0 system minutes	Number of events	24	-	17
>1.0 system minutes	Number of events	2	-	2
Average outage duration	Minutes	698	-	871

14.6 D-factor

ERA required amendment 38:

Western Power must delete proposed new sections 7.6.6 to 7.6.10 from the access arrangement.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

1229. The D-factor is an adjustment mechanism that allows Western Power to recover the efficient costs associated with innovative or non-network solutions that that are undertaken in lieu of traditional network capital investment.

1230. Over the AA4 period, the D-factor will become an increasingly important part of our investment program. This is because it will facilitate our continued progression of innovative solutions and demand management activities. These initiatives are all aimed at delivering efficiencies and achieving benefits for our customers.

1231. In the AA4 proposal, Western Power submitted amendments to the D-factor, which provided:

- a clear process for Western Power to make a submission to the ERA approval for D-factor costs outside of an access arrangement review
- a requirement for the ERA to make a decision on whether the D-factor costs meet the requirements of section 6.40 and 6.41 of the Access Code within 25 business days of receipt of a submission from Western Power.

1232. We considered these two relatively minor amendments would provide greater certainty that costs can be recovered and thereby not discourage Western Power from pursuing innovative and non-network solutions.

1233. However, the ERA rejects these amendments, stating:

> *The D-factor is not intended to provide incentives for Western Power to pursue demand management activities. Rather it was introduced to allow the retrospective recovery of non-capital costs during an access arrangement.*[305]

and:

> *The Access Code includes provisions for Western Power to submit an application for approval of non-operating costs at any time during an access arrangement. The ERA considers there is no need for an additional D-factor non-capital costs test (as proposed by Western Power), and in any case, such a test is not contemplated under the Access Code.*[306]

1234. We disagree with the ERA's conclusions. We also maintain that the proposed additional certainty that would be provided by our amendments will be of utmost importance over the AA4 period, as we intend to make greater use of the D-factor in an attempt to defer costly network augmentations.

1235. A timely, clear and robust process for recovering the cost of any non-capital alternative options will ensure that capex is not unduly preferred.

1236. We believe further consideration is required on how to improve the incentive scheme for AA5. However, we consider that our proposal for AA4 is a step towards improving the incentive of the current D-factor scheme by ensuring non-network solutions are not unduly discouraged.

1237. We have addressed each of the ERA's concerns with our proposed amendments in the following sections.

14.6.1 The D-factor is not intended to provide incentives to pursue demand management activities

1238. The ERA's view in paragraph 1231 is contrary to its statement in paragraph 1224 of the draft decision, where the ERA asserts that the D-factor operates to remove the disincentive arising from the Access Code not allowing the retrospective recovery of non-capital costs.

1239. Our proposal was not designed to incentivise demand management activities but to weaken the disincentive for non-network options. It is thus entirely consistent with the ERA's statement of purpose for the D-factor scheme and the Access Code objective. We accept that the D-factor is not intended to provide incentives to pursue demand management activities, but rather, as the ERA notes in its AA2 draft decision; *remove disincentives for Western Power to implement non-network alternatives*.[307]

1240. We consider our proposed amendments to the D-factor scheme meet the ERA's objective in that they provide more clarity to the operation of the scheme, and therefore further weaken the disincentive.

14.6.2 The Access Code includes alternative recovery provisions

1241. The ERA argues that sections 6.76 to 6.80 of the Access Code provide an adequate alternative approach for Western Power to recover non-capital costs in-period. We disagree.

1242. Sections 6.76 to 6.80 of the Access Code are distinct from the D-factor scheme provisions in that they:

- do not include a reference to section 6.41 of the Access Code as the D-factor scheme does. Any application would be limited to an approval under section 6.40 of the Access Code
- do not provide for the approved amount to be financially neutral for Western Power.

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305 Paragraph 1231, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

306 Paragraph 1232, ibid.

307 Paragraph 1029, *Draft Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, ERA, July 2009.

1243. For these reasons, the reliance on sections 6.76 to 6.80 of the Access Code rather than the proposed process, would provide a disincentive to adopting any non-network alternatives for major network augmentation projects over the AA4 period. This is contrary to the Access Code objective and would result in a further disincentive to undertake non-network solutions.

14.6.3 The D-factor is not expressly considered in the Access Code

1244. We note that express authority in the Access Code is not required. Section 4.29(b) of the Access Code, provides for the ERA to approve items, including the proposed pre-approval process in the D-factor scheme, in an access arrangement. Section 4.29 of the Access Code states:

> *4.29 The Authority:*
>
> *….*
>
> *(b) may in its discretion approve a proposed access arrangement containing something not listed in section 5.1; …*

1245. We note that in its AA2 Final Decision, the ERA considered that the D-factor scheme *is consistent with the requirements of the Access Code*[308]. Further, the ERA stated it considers *the D-factor has been effective in enabling Western Power to adopt non-network options without exposing customers to higher costs from inaccurate forecasts of network control service costs.*[309] We agree that the D-factor has been successful in helping us balance the capex and opex incentives.

1246. Our proposed amendments to the access arrangement do not change the intent or objective of the scheme, nor are they intended to provide for an additional D-factor non-capital costs test. They are designed to maintain our D-factor scheme as approved by the ERA in AA3, and clarify the operational process under which an application may be submitted, reviewed and approved. These amendments will provide greater certainty, transparency and a more timely and robust process, and will therefore better achieve the Access Code requirements.

1247. This is becoming more important as we now have more non-network options at our disposal and are experiencing a more rapid development and uptake of innovative non-network approaches.

14.6.4 Consistency with the Access Code objective and chapter 5

1248. In its draft decision, the ERA states:

> *If the ERA considers the Access Code objective and requirements of chapter 5 are satisfied it must approve the access arrangement. The ERA may not reject a proposed access arrangement on the grounds that another form of access arrangement might be better or more effectively satisfy the Access Code objective and the requirements set out in chapter 5*[310]*.*

1249. While the ERA has identified what it considers is an alternative approach to our proposed amendments, the ERA has failed to demonstrate that our proposed amendments would be inconsistent with the Access Code objective or are non-compliant with the requirements under chapter 5 of the Access Code.

1250. We therefore do not accept the ERA's required amendments and maintain that further information pertaining to the approval process is necessary and should be provided for in the access arrangement.

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308 Para 1205, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, ERA, December 2009.

309 Paragraph 1230, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

310 Paragraph 22, ibid.

14.6.5 Further amendments to allow for consultation

1251. We note that Synergy submitted that the 25 business day timeframe may be too short for the ERA to make an adequate assessment of our D-factor application. We proposed this timeframe to align with the timeframe under other sections of the Access Code.

1252. We agree that the timeframe may be too short if the ERA wish to consult on the application.

1253. Appendix 7 of the Access Code outlines the full consultation process used in certain places of the Access Code. In its entirety, this process would involve the following:

- The ERA must publish the item.
- The ERA may publish an issues paper.
- The ERA must publish an invitation for submissions.
- Submissions may be made within 10 to 20 business days of the invitation being published.
- Where the ERA decides:
  - to make, and consult on a draft decision:
    - The ERA must publish the draft decision and an invitation for submissions within two months.
    - Submissions may be made within 10 to 20 business days of the draft decision being published.
    - The ERA must make a final decision within 30 business days of the close of submissions.
  - not to make a draft decision, the ERA must make a final decision within two months.

1254. This could result in a consultation process of up to five months, which Western Power does not consider provides it with certainty in a sufficiently timely manner to allow it to pursue non-network solutions. As such, Western Power considers it appropriate to limit the total timeframe for consultation under Appendix 7 to 45 business days. This timeframe aligns with the ERA's prescribed timeframes for considering:

- major augmentation proposals for the purposes of the Regulatory Test under section 9.18 or 10.44 of the Access Code are capped at 45 business days
- applications for an exemption from the Technical Rules under section 12.44 of the Access Code are capped at 45 business days.

1255. We consider any decision and consultation process associated with a D-factor application is likely to be commensurate with these similar processes, and believe these timeframes would appropriately balance the need for a timely decision, with an adequate timeframe for the ERA to sufficiently consider our application.

1256. We have therefore proposed further amendments to section 7.6.7 of the access arrangement to provide for the ERA to either make a determination:

- within 25 business days of receiving an application under section 7.6.6 of the Access Code, where it has decided not to consult the public in accordance with Appendix 7 of the Access Code
- within 45 business days of receiving an application under section 7.6.6 of the Access Code, where it has decided to consult the public in accordance with Appendix 7 of the Access Code.

15. Trigger events

1257. This section details Western Power's response to the ERA's amendment to trigger events for the AA4 period.

ERA required amendment 39:

Section 8.1.2 of the proposed revised access arrangement must be deleted.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1258. In the AA4 proposal, Western Power submitted an additional trigger event in the access arrangement relating to 'any other government energy reforms'. This new trigger event was proposed in light of the recent Electricity Market Review and subsequent reforms that resulted in significant unforeseen costs being imposed upon Western Power. The trigger event was proposed to provide certainty that the efficient costs associated with any similar Government-led reforms in the future could be recovered.

1259. The ERA rejects our proposed additional example of what may constitute a trigger event, and requires Western Power to remove section 8.1.2 in its entirety. This is on the basis that:

> *The ERA considers the specification of the trigger event is adequately covered in section 8.1.1 of the access arrangement. Section 8.1.2 is unnecessary and creates confusion – the section should be deleted from the access arrangement.*[311]

1260. We accept the ERA's required amendment and will use the definition of a trigger event provided in section 8.1.1 of the access arrangement to re-open the access arrangement during the AA4 period, as required.

1261. However, we note that section 4.38(a) of the Access Code similarly provides for the ERA to re-open the access arrangement in-period. This section allows the ERA to re-open the access arrangement for **<u>any</u>** impact of a significant unforeseen event where the advantages of the revision outweigh the cost.

1262. As it is currently drafted, section 8.1.1 of the access arrangement unnecessarily limits this trigger for Western Power to financial impacts only. This is inconsistent with the ERA's provision and the provisions under section 4.41A of the Access Code. We consider Western Power should be able to propose re-opening the access arrangement for reasons broader than financial impacts. These may include, for example, impacts on our service performance measures.

1263. On this basis, we propose to amend section 8.1.1 of the access arrangement as follows:

> *8.1.1 Pursuant to section 4.37 of the Code a trigger event is any significant unforeseen event which has a materially adverse ~~financial~~ impact on Western Power and which is:*
>
> *a) outside the control of Western Power; and*
>
> *b) not something that Western Power, acting in accordance with good electricity industry practice, should have been able to prevent or overcome; and*
>
> *c) so substantial that the advantages of making a variation to this access arrangement before the end of this access arrangement period outweigh the*

311 Paragraph 1257, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

disadvantages, having regard to the impact of the variation on regulatory certainty.

16. Supplementary matters

1264. This section details Western Power's response to the ERA's amendments to supplementary matters.

ERA required amendment 40:

Section 9.1 of the proposed revised access arrangement, which sets out general provisions for supplementary matters, must be amended in accordance with paragraph 1269 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1265. Western Power accepts the ERA's proposed amendment to move some of the proposed drafting related to its functions under the Wholesale Electricity Market Rules to an explanatory note.

1266. We have reviewed the explanatory note and made the following minor drafting amendments shown with underline/strikethrough.

*9.1.1 Western Power will discharge ~~it's~~ the obligations it has under the Wholesale Electricity Market Rules (**WEM Rules**) as in force from time to time relating to ~~for~~ balancing requirements, ancillary services, trading and settlement requirements in accordance with the ~~Wholesale Electricity Market~~ WEM Rules. ~~and, in accordance with those rRules~~, Western Power will also support the Australian Energy Market Operator (AEMO) in the discharge of its functions including by providing information to AEMO as required by the ~~Wholesale Electricity Market~~ WEM Rules.*

{Note: Previous versions of the access arrangement have referred, in the Supplementary Matters chapter, to balancing requirements, ancillary service, trading and settlement requirements.

Under the WEM~~holesale Electricity Market~~ Rules these functions are now principally undertaken by the ~~Australian Energy Market Operator ("~~AEMO~~")~~. This occurred when the System Management functions were transferred from Western Power to AEMO on 1 July 2016.

As ~~at~~ from 1 July 2016~~2 October 2017~~ ~~this access arrangement is prepared by Western Power, the~~ Western Power's principal role in respect to these functions under the WEM Rules ~~Western Power will have~~ is to provide network information to AEMO to support settlements and balancing.}

ERA required amendment 41:

Section 9.2.1 of the proposed revised access arrangement, which sets out supplementary matters for line losses, must be amended in accordance with paragraph 1271 of this draft decision.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1267. The ERA proposes to make changes to the access arrangement to include a reference to Western Power's obligations in relation to transmission line losses under the Technical Rules. This request was made in a submission to the ERA by Mr Stephen Davidson.

1268. Supplementary matters are those that may be considered extraneous to the performance of Western Power's functions as a network operator, for example, facilitating the operation of the wholesale electricity market.

1269. We consider that the performance of our functions in a prudent and efficient manner, including but not limited to the calculation of line losses, is adequately addressed in our proposed revised access arrangement.

1270. The reference to the treatment of line losses in the access arrangement is a reference to the calculation of the MW of lost energy between the generation of electricity, and the consumption point. It is calculated by Western Power as the electricity lost from traversing network assets which have some resistivity. The line loss calculation is conducted by Western Power for AEMO for the purposes of settlement of the wholesale electricity market. This calculation of lost energy (line losses) is distinct from our role with respect to the re-energisation of assets after an interruption or outage event which is not a 'supplementary' matter.

1271. We have reviewed the Technical Rules and do not consider there are any specific obligations in Chapter 5 (or elsewhere in the Technical Rules) that would require any reference in the supplementary matters section of the access arrangement. That is, the Technical Rules do not deal with treatment of line losses.

1272. Further, the effect of the required amendment means that the supplementary matter now contemplates line losses in respect to only the transmission system. Western Power's obligations in respect to the calculation of line losses under the WEM Rules are set out in WEM Rules clause 2.27 'Determination of Loss Factor'. These obligations apply to the transmission and distribution networks. The supplementary matters section should appropriately reflect Western Power's requirements under the WEM Rules.

1273. Moreover, Western Power must comply with the obligations imposed on it in the Technical Rules, whether or not they are identified in the access arrangement.

1274. For the reasons outlined above Western Power has not made the required amendment to the proposed revised access arrangement.

17. Standard access contract (ETAC)

1275. The ERA requires 20 amendments to the standard access contract (hereinafter referred to as the standard Electricity Transfer Access Contract, or ETAC). This section details Western Power's response to each required amendment to the ETAC in turn.

1276. The revised ETAC, which reflects the various amendments in response to the ERA's draft decision, is provided at Appendix A to the revised proposed access arrangement.

17.1 Electricity transfer provisions for services (clause 3)

ERA required amendment 42:

Clause 3.1(c) of the electricity transfer access contract must read:

"For each Service at each Connection Point, the User must endeavour, as a Reasonable and Prudent Person, to ensure that the rate at which electricity is transferred into or out of the Network by or on behalf of the User does not exceed the Contracted Capacity for that Service."

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

1277. In its AA4 proposal, Western Power had proposed to delete from clause 3.1(c) the words '*endeavour, as a Reasonable and Prudent Person, to*'. Western Power considers the standard of endeavour is a low one and that, given the potential threat to the integrity of the network arising from contracted capacity being exceeded, the appropriate standard is the user must ensure contract capacity is not exceeded.

1278. The ERA does not agree with this change and requires Western Power's proposed amendment to be reversed.

1279. We understand the concerns of retailer users that there are practical difficulties in them controlling their customer's network use within contracted capacity levels given they are not the ones actually consuming the electricity. In respect of this issue it would be preferable if the end-use customer had a direct contract with Western Power requiring them not to exceed their contracted capacity. Unfortunately the Western Australian electricity regulatory structure does not facilitate this as the contractual structure is Western Power → user → end-use customer.

1280. One way to address the above issue would be to require users to procure a direct covenant from their end-use customers in favour of Western Power not to exceed their contracted capacity. However we recognise there may be some practical difficulties in obtaining such a covenant, at least in the short term. It could only be obtained at the point in time when end-use contracts came up for renegotiation which is not that frequent given the typically long terms associated with these contracts.

1281. We have further considered clause 3.1(c) and have proposed a revised approach. Under this approach the 'must ensure' criteria will be limited to those connection points which pose the greatest threat to the network if contracted capacity is exceeded. For other connection points the standard will remain as '*endeavour, as a Reasonable and Prudent person.*'

1282. Western Power submits the '*must ensure*' criteria should apply to users who own the facilities or generating plant at the connection point or who are required to appoint controllers at the connection point under clause 6.1 of the ETAC. We see no reason a user in control of its own equipment cannot put in place the protection and control systems to ensure contracted capacity is not exceeded. Similarly in the case of controllers, at the time a controller is nominated the user should ensure the appropriate controls are in place.

1283. At present these categories of users only have an obligation of a reasonable and prudent person to comply with their contracted capacity constraints. We submit this is not appropriate and is inconsistent with clause 4.30(c) of the Code which requires the ERA to have regard to the operational and technical requirements necessary for the safe and reliable operation of the network when determining to approve an access arrangement.

1284. We recognise there will be existing controllers who are only contractually obligated to the endeavour as a reasonable and prudent person standard. A user may argue it is unfair to change the standard applicable to the user as they may not have negotiated this standard with the controller. However such an argument would be in error as this new regime will only commence to apply to users at the time they negotiate new Electricity Transfer and Access Contracts with Western Power.

1285. To reflect the comments provided by ERM Power and Alinta Energy in their AA4 submissions, we have provided in clause 3.1(f) and 3.1(g) that clause 3.1(c) does not apply where a generator is directed under the Market Rules to exceed its contracted capacity or where Western Power agrees to the generator exceeding its contracted capacity.

1286. While Western Power's proposed regime does not provide the optimal protection for the network Western Power was seeking, it does address those connection points which will pose the greatest threat to the network.

1287. The proposed drafting which Western Power has been included in Appendix A to the revised proposed access arrangement to give effect to the proposed regime in clause 3.1 is set out below:

(c) For each Service at each Connection Point which falls within a category referred to in clause 3.1(e), the User must ensure that the rate at which electricity is transferred into or out of the Network by or on behalf of the User does not exceed the Contracted Capacity for that Service.

(d) For each Service at each Connection Point which does not fall within a category referred to in clause 3.1(e), the User must endeavour, as Reasonable and Prudent Person, to ensure that the rate at which electricity is transferred into or out of the Network by or on behalf of the User does not exceed the Contracted Capacity for that Service.

(e) The relevant categories for the purpose of clause 3.1(c) are each of the following:

(i) any Service at a Connection Point where the User owns, operates or controls the Facilities and Equipment;

(ii) any Service at a Connection Point at which the User owns, operates or controls the Generating Plant; and

(iii) any Service at a Connection Point for which the User is required to nominate a Controller under clause 6.1.

(f) The User is not in breach of clause 3.1(c) where and to the extent a Generator exceeds the Contracted Capacity at a Connection Point in compliance with a direction given under the Market Rules or in compliance with any procedures published by Western Power from time to time authorising temporary exceeding of Contracted Capacity.

(g) The User is not in breach of clause 3.1(c) or clause 3.1(d) where and to the extent it exceeds the Contracted Capacity with the prior consent of Western Power.

(h) Western Power provides the Services under this Contract to the User and does not provide any such Services to the Indemnifier. Western Power's sole liability in connection with the provision of the Services (including any failure of, or defect in provision of the Services) is to the User and Western Power has no liability of any nature to the Indemnifier in connection with the provision of the Services.

17.1.1 User may select services (clause 3.2)

ERA required amendment 43:

The electricity transfer access contract must be amended to correct a formatting (numbering) error to show new clauses 3.2(c) and 3.2(d).

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1288. The ERA has identified that clause 3.2(b) should have been split into clauses 3.2(b) and 3.2(c).

1289. Western Power accepts there was a formatting (numbering) error. However, on the basis the ERA requires the split out clause 3.2(c) to be deleted (as per required amendment 44), we have not made this amendment. The split out clause 3.2(c) has been deleted in Appendix A to the revised proposed access arrangement.

ERA required amendment 44:

Proposed new clauses 3.2(c) and 3.2(d) must be deleted from the electricity transfer access contract.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1290. The ERA has proposed the deletion of clauses 3.2(c) and 3.2(d) which were proposed by Western Power to allow for Western Power to initiate a change to the covered service. Clauses 3.2(c) and 3.2(d) proposed by Western Power were as follows:

(c) In respect of Services provided to Small Customers, Western Power may, by notice to the User, change the Service applicable to the Connection Point for that Small Customer where:

(i) Western Power modifies or replaces the equipment at or in proximity to the Connection Point (including the Metering Equipment) and as a result of that modification or replacement Western Power considers the Service should be changed; or

(ii) the change is made in connection with new policies implemented by Western Power in respect of Small Customers (for example changes to the type of Metering Equipment to be used).

(d) Where Western Power changes the Service applicable to a Connection Point for a Small Customer then the User may not, unless Western Power agrees otherwise, request that the

Connection Point revert to the prior Service applicable to the Small Customer at that Connection Point.

1291. Western Power accepts this amendment and has deleted clauses 3.2(c) and 3.2(d) from Appendix A to the revised proposed access arrangement.

17.1.2 Eligibility criteria (clause 3.3)

ERA required amendment 45:

Clause 3.3 of the electricity transfer access contract should be amended in accordance with paragraph 1337 of this draft decision to ensure that a user will not be in breach of its obligation in the event its breach arises because of Western Power.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1292. The ERA has proposed to amend clause 3.3 as follows:

(a) Subject to clause 3.3(b), the User must in relation to each Reference Service Point, comply with the Eligibility Criteria applicable to the Reference Service provided, or to be provided, at the Reference Service Point.

(b) No breach of clause 3.3(a) occurs where the User is unable to comply with its obligation under clause 3.3(a) as a result of a breach by Western Power of clause 3.2(b).

1293. Western Power accepts the ERA's approach but proposes to use the drafting '*to the extent the User is unable to comply*' due to Western Power's breach rather than '*where*'.

1294. We consider this better reflects the fact that if there is a breach by Western Power it is more likely to result in partial non-compliance with the eligibility criteria rather than a complete inability to comply with those criteria. That said, we also note that generally we would not expect a failure to comply with the Applications and Queuing Policy to mean the user cannot continue to comply with eligibility criteria (particularly as it should have complied with those criteria to date).

1295. We have amended clause 3.3 in Appendix A to the revised proposed access arrangement as follows:

(a) Subject to clause 3.3(b), the User must in relation to each Reference Service Point, comply with the Eligibility Criteria applicable to the Reference Service provided, or to be provided, at the Reference Service Point.

(b) ~~No breach of clause 3.3(a) occurs where~~The User is not in breach of clause 3.3(a) to the extent the User is unable to comply with its obligation under clause 3.3(a) as a result of a breach by Western Power of clause 3.2(b).

17.2 Electricity transfer provisions for controllers (clause 6)

ERA required amendment 46:

Given the changes to clause 6.2(b) of the electricity transfer access contract, clause 33.4 of contract must be amended in accordance with paragraph 1342 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1296. The ERA has proposed to amend clause 33.4 as follows:

33.4 Permitted disclosure

(a) An Information Recipient may disclose or allow to be disclosed …

(b) A User may disclose or allow to be disclosed a copy of this Contract to a Controller to whom the User will or has entered into a contract with as required by clause 6.

(c)~~(b)~~ Nothing in this clause 33.4 limits Western Power's obligations …

1297. Western Power accepts the ERA's proposed amendment to clause 33.4 with very minor wording corrections. Western Power's wording corrections have been included in Appendix A to the revised proposed access arrangement as follows:

(b) The User may disclose or allow to be disclosed a copy of this Contract to a Controller with whom the User will enter, or has entered into, a contract as required by clause 6.

17.3 Electricity transfer provisions for security for charges (clause 9)

ERA required amendment 47:

Clause 9(i) of the electricity transfer access contract should be amended to capitalise the term "services" as follows.

" … the aggregate amount of cash deposit held by Western Power (including interest and after deducting any fees, charges and taxes associated with maintaining the interest bearing account) exceeds the Charges for two months' ~~s~~Services Western Power will, within a reasonable time…"

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1298. Western Power accepts this amendment and has made the necessary changes in Appendix A to the revised proposed access arrangement.

17.4 Technical compliance provisions for technical characteristics of facilities and equipment (clause 13)

17.4.1 Use of the words “materially modify” and “adversely impact”

ERA required amendment 48:

Clause 13(c)(i) of the electricity transfer access contract must be amended to expressly set out the characteristics of generating plant that, if changed, will constitute material modifications for the purpose of that clause.

Proposed clause 13(c)(ii) must be deleted from the electricity transfer access contract unless the modifications that are contemplated by clause 13(c)(ii), which would not fall within clause 13(c)(i), are clearly identified.

Western Power’s response:

Western Power does not accept this amendment and proposes a modified position.

1299. Clause 13(c)(i) deals with changes to plant that activate obligations under the Applications and Queuing Policy, specifically in relation to changes to plant which may require a modification to the network. It is and has always been the user’s responsibility to assess if it is making a change to its plant that may in turn require a modification to the network and, if so, approach Western Power through the Applications and Queuing Policy process. Clause 13(c)(i) is essentially the contractual recognition of the Applications and Queuing Policy obligation.

1300. Clause 13(c)(ii) deals with a different scenario. It deals with changes to plant that will not require modification to the network but which changes might adversely impact the safety or security of the network (particularly if not done in a specified manner). For example, a change to the plant may not require a modification to the network but may require Western Power to operate the network in a different manner. The intent of clause 13(c)(ii) is to create the appropriate information flow so the impact of these modifications can be assessed before they are made, and if there are risks Western Power can consider and act upon them. While it is the user’s responsibility to ensure their plant complies with the contract, at the same time changes they make can impact the network and other users.

1301. In short, the rationale for the inclusion of clause 13(c)(ii) is to provide a process for Western Power to be notified of material changes to the plant (but which changes do not activate the Applications and Queuing Policy) so as to allow Western Power to assess in advance any potential adverse impact on the network. We recognise there is some inherent ambiguity in the concept of ‘material’ but also note that it is a concept which is commonly employed in contractual (and indeed legislative) documents. While we consider material is the best concept to use (in the sense that what should be out of scope is immaterial changes), we recognise the ERA’s concerns and have therefore put forward criteria as to how to assess what is material.

1302. We propose the materiality test for the purposes of clause 13(c)(ii) would be that either:

- the modification involves expenditure of more than AUD$100,000; or
- the modification is one which, consistent with Good Electricity Industry Practice, requires engineering review before being made.

1303. We consider both of these are reliable indications that a modification is sufficiently material and Western Power should be notified prior to the modification being undertaken. Also, to further clarify the concept, we propose clarifying that like for like replacement of parts does not fall within clause 13(c)(ii).

1304. The ERA requires:

> *Clause 13(c)(i) of the electricity transfer access contract must be amended to expressly set out the characteristics of generating plant that, if changed, will constitute material modifications for the purpose of that clause.*

1305. We do not consider we are in a position to do this – Western Power cannot anticipate every possible change to a plant that may activate the Applications and Queuing Policy. The user must consider the definition of 'connection application' in the Applications and Queuing Policy and assess if it may be within that definition. The user can always consult with Western Power as to specific proposals to assess if they are within or outside the Applications and Queuing Policy and that Policy has processes for this. We note clause 13(c)(i) is essentially the same clause as included in the AA3 ETAC.

1306. Western Power proposes to amend clause 13(c)(ii) to provide clearer guidance as to what will fall within that clause. This amendment clarifies to users when the clause is activated – if they are spending more than AUD$100,000, or are or should, in accordance with good electricity industry practice, be obtaining review by an independent engineer of their proposal, they should also consult Western Power.

1307. We have amended clause 13(c) of Appendix A to the revised proposed access arrangement as follows:

(c) The User must not materially modify any Generating Plant connected at a Connection Point unless:

(i) where such modification requires an Application under the Applications and Queuing Policy:

(A) the User makes such an Application; and

(B) the Application is processed by Western Power under the Applications and Queuing Policy, resulting in an Access Offer for the change, which the User accepted;

(ii) where such modification does not require an Application under the Applications and Queuing Policy and relates to a Generating Plant owned by a person other than a Small Customer:

(A) the User notifies Western Power of the modifications to the Generating Plant in writing at least 60 Business Days prior to the modifications being made; and

(B) the modified Generating Plant does not adversely impact the safety or security of the Network.

(d) <u>For the purposes of clause 13(c)(ii) a modification is material only if:</u>

<u>(i) it involves expenditure of more than $100,000; or</u>

<u>(ii) the modification is one which, consistently with Good Electricity Industry Practice, requires review by a duly qualified engineer before being made.</u>

(e) <u>The replacement of like for like parts within a Generating Plant or the replacement of parts in the ordinary course of maintenance and repair is not a material modification for the purposes of clause 13(c)(ii).</u>

17.4.2 Written notification period

ERA required amendment 49:

Subject to clause 13(c)(ii) remaining in the electricity transfer access contract, the notification period in clause 13(c)(ii) must be amended from 60 to 30 days.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1308. Western Power is concerned that 30 days will not provide sufficient time to adequately and safely assess the impact of a proposed modification, which will likely require input from various technical personnel within Western Power such as planning engineers and network controllers.

1309. We note that given we have now defined a materiality test within clause 13(c)(ii), the types of modifications that will fall within 13(c)(ii) are ones that will be made with significant prior planning. In this context, we do not consider 60 days unreasonable.

17.4.3 Notification to User

ERA required amendment 50:

Subject to clause 13(c)(ii) remaining in the electricity transfer access contract, clause 13(c)(ii) must contain an express obligation for Western Power to notify the user within the notice period if it forms the view that the modification will have an adverse impact on safety or security, failing which the modification can proceed.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1310. Western Power agrees with the principle of the ERA's amendment. However, we have modified the wording so that it allows the user to proceed, unless Western Power gives a notice raising an objection.

1311. We have also made clear in the clause that any advice provided by Western Power does not relieve the user of the obligation to ensure their plant complies with the requirements of the contract including the Technical Rules. That is, by giving notice to Western Power the user cannot transfer responsibility for ensuring the integrity of its plant from the user to Western Power.

1312. The following clause 13(f) has been included in Appendix A to the revised proposed access arrangement:

> (f) If Western Power does not notify the User within 60 days of receipt of notice under clause 13(c)(ii) that the modification may adversely impact the safety or security of the Network the User may proceed to make the modification. However nothing in this clause derogates from the User's responsibility to ensure the Generating Plant complies with the requirements of this Contract including the obligations to comply with the Technical Rules.

1313. We have also made a minor amendment to the drafting amendment to the drafting of clause 19.5(d) proposed by the ERA so as to identify the terms 'parties' and 'party' as defined by capitalising them.

17.5 Common provisions for limitation of liability and indemnity (clause 19)

17.5.1 Limitation of liability (clause 19.5(c))

ERA required amendment 51:

Clause 19.5 of the electricity transfer access contract must be amended in accordance with paragraph 1383 of this draft decision to amend the drafting of clause 19.5(c) and insert a new clause 19.5(d).

To support new clause 19.5(d) the term "material change" needs to be added to schedule 1 of the electricity transfer access contract in accordance with paragraph 1384 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1314. The ERA proposes to include a new clause 19.5(d) as follows:

> (d) At the end of each three-year period from the Commencement Date, if there has been a Material Change affecting the liability of a party under this Contract, then the parties must negotiate in good faith to reset the monetary caps on liability in this clause 19.5. If the parties are unable to agree on re-setting the monetary caps on liability, the matter shall be determined by an expert nominated by the parties or, failing agreement, nominated by the Chairperson of the Chartered Institute of Arbitrators (Western Australian Chapter) or their nominee and the determination of the expert shall be final and binding upon the parties.

and the following clarifying words in clause 19.5(c):

> (c) Subject to clause 19.5(d, ~~T~~the monetary caps…

and a new definition of 'Material Change' in Schedule 1 as follows:

> Material Change any event, condition or change which materially alters or could reasonably be expected to materially alter the risk of a party under this Contract, the nature of any Claim that can be made under this Contract or both.

1315. The definition of 'Material Change' proposed by the ERA is relatively broad. We consider it should be limited to changes in risk profile due to changes in the regulatory environment or market structure. That is, changes to a party's own position or internal arrangements should not be a basis for reopening the contractual liability structure – the relevant cause of reopening negotiations should be an external factor.

1316. Having regard to the matters raised above we propose implementing the proposed amendments to clauses 19.5(c) and (d) but replacing the ERA's proposed definition of 'Material Change' in Schedule 1 with the following which has been included in Appendix A to the revised proposed access arrangement:

> Material Change any change to the regulatory environment or market structure of the Western Australian electricity market which materially alters or could reasonably be expected to materially alter the risk of a Party under this Contract, the nature of any Claim that can be made under this Contract or both.

17.5.2 Apportionment of liability (clause 19.8)

ERA required amendment 52:

Clause 19.8 of the electricity transfer access contract must be amended in accordance with paragraph 1388 of this draft decision to make minor drafting amendments.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1317. The ERA proposes to amend clause 19.8(a) as follows:

(a) … is limited to the proportion of the damage suffered by Western Power as a consequence of the Default, negligence or fraud of ~~the~~ either or both of the User or the Indemnifier giving rise to the liability or indemnity.

1318. The ERA also proposes deletion of '*under clause 19.2(b)*' from clause 19.5(c)(ii) as those words are unnecessary. We assume this is a reference to removing the words from clause 19.8(c)(ii) rather than clause 19.5(c)(ii). We agree to this amendment. Clause 19.8(c)(ii) is amended in Appendix A to the revised proposed access arrangement as follows:

(ii) except as provided in clause 19.8(c)(i), clause 19.8(a) does not apply to reduce the Indemnifier's indemnification obligation ~~under clause 19.2(b)~~.

17.5.3 Apportionment of liability (clause 19.11)

ERA required amendment 53:

Clause 19.11(a) of the electricity transfer access contract must be amended in accordance with paragraph 1392 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1319. The ERA proposes to amend clause 19.11 as follows:

19.11 Intermediary Indemnity

Where:

(a) the User is the Intermediary (as defined in the Market Rules) of a person <u>and in so far as they are registered as a Rule Participant (as defined in the Market Rules)</u>; and

1320. Western Power understands the concern is to ensure the user is registered in the market as the Intermediary. We agree in principle with this but propose to further clarify the drafting in Appendix A to the revised proposed access arrangement as follows:

19.11 Intermediary Indemnity

Where

(a) the User is registered under the Market Rules as the Intermediary (as defined in the Market Rules) of a person; and

17.6 Common provisions for notices (clause 35)

ERA required amendment 54:

The following consequential amendments that arise from the deletion of clause 35.1(b)(iv) must be made to the electricity transfer access contract.

- The words "facsimile copy" should be deleted from clause 1.1(d).
- The word "facsimile number" should be deleted from clause 36.
- The words "facsimile number" from Part 1 and Part 2 of the table in schedule 6 should be deleted.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1321. Western Power accepts this amendment and has made the necessary changes in Appendix A to the revised proposed access arrangement.

17.7 Other proposed changes

17.7.1 “Claim”

ERA required amendment 55:

The term “Claims” in Part 1(a)(i)(A) of schedule 5 of the electricity transfer access contract must be amended to correct the use of the word claims as follows.

“public liability insurance for a limit of not less than $50 million or the maximum liability of the User under clause 19.5 (whichever is greater) in the aggregate of all ~~C~~claims made in an Insured Year; and”

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

1322. Western Power accepts this amendment and has made the necessary changes in Appendix A to the revised proposed access arrangement.

17.7.2 Clause 6.2 – “contract”

ERA required amendment 56:

Clause 6.2(b) of the electricity transfer access contract must be amended to correct the use of the word *contract* in accordance with paragraph 1430 of this draft decision.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

1323. Western Power accepts this amendment and has made the necessary change in Appendix A to the revised proposed access arrangement.

17.7.3 Clause 7.1 – “tariff” and “consumption”

ERA required amendment 57:

Clause 7.1 of the electricity transfer access contract must be amended to correct the use of the words *tariff/s* and *consumption* in accordance with paragraphs 1431 and 1432 of this draft decision.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

1324. Western Power accepts this amendment and has made the necessary change in Appendix A to the revised proposed access arrangement.

17.7.4 Clause 12.2 – “user” and “party”

ERA required amendment 58:

Clause 12.2 of the electricity transfer access contract must be amended to correct the use of the words *user* and *party* in accordance with paragraph 1436 of this draft decision.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

1325. Western Power accepts this amendment and has made the necessary change in Appendix A to the revised proposed access arrangement.

17.7.5 Clause 19 and clause 35.4(d) – “party” / “parties”

ERA required amendment 59:

Clauses 19.1, 19.6 and 35.4(d) of the electricity transfer access contract must be amended to correct the use of the word party (or parties) in accordance with paragraph 1438 of this draft decision.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

1326. Western Power accepts this amendment and has made the necessary change in Appendix A to the revised proposed access arrangement.

17.7.6 Clause 27.1 – “defaults”

ERA required amendment 60:

Clause 27.1 of the electricity transfer access contract must be amended to correct the use of the word *default* in accordance with paragraph 1439 of this draft decision.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

1327. Western Power accepts the term “Default” should not be capitalised in clause 27.1 and has made the necessary change in Appendix A to the revised proposed access arrangement.

1328. In the course of reviewing the required capitalisation changes, we identified one further capitalisation error. The term ‘Law’ is capitalised in the guarantee in Schedule 8. However, law is not actually defined and the use of ‘law’ was therefore correct. We have corrected this matter in Appendix A to the revised proposed access arrangement

17.7.7 Clause 22 – Force majeure

> **ERA required amendment 61:**
>
> Clause 22.3(a) of the electricity transfer access contract must be amended to read:
>
> "promptly notify the other Party of the occurrence of the Force Majeure Event and in any event within two days of the occurrence of the Force Majeure Event; and".
>
> **Western Power's response:**
>
> Western Power does not accept this amendment and maintains its original position.

1329. As Western Power understands it, clause 22.3(a) is about giving notice to confirm the contractual consequences of an event. This is why notice is only required if force majeure continues for more than two days. The two-day period is linked to clause 7.3(a) where a rebate is allowable on fixed charges if force majeure continues for more than two days.

1330. The rationale for the change in clause 22.3(a) seems to be a concern the notice is linked to management of the force majeure event. This is not the case.

1331. If a force majeure event has occurred then users are likely to know very soon after such event occurs, as there is likely to be community awareness about the event and/or the power supply will have been significantly impacted (although impacts to power supply are not necessarily caused by force majeure). If power supply is impacted as a result of the force majeure, Western Power's focus will not be on issuing contractual notices, rather it will focus on restoring power supply and coordinating with users and the AEMO to address the impact of the outage.

1332. It is not desirable that during this critical emergency response time Western Power be distracted by issuing contractual notices, which in themselves do not address the event or provide a means to resolve it. Contractual consequences can be considered once the event has been resolved.

1333. We have concerns about the ERA's required amendment and in response propose a regime whereby notices are given as soon as reasonably practicable and in any event within 10 business days of becoming aware of the force majeure event occurring.

1334. We therefore propose the following addition to clause 22.3(a) in Appendix A to the revised proposed access arrangement:

> A notice under clause 22.3(a) must be given as soon as reasonably practicable and in any event within 10 Business Days of a Party forming the view an event is or is likely to be a Force Majeure Event.

17.7.8 Insurance

1335. In the course of responding to the draft decision Western Power has identified an issue with clause 21.3 of the standard ETAC. The clause as written requires the user to ensure its insurance is in the joint names of itself and Western Power or that Western Power is endorsed on policies. In reality this is not what happens and is not practicable. In practice Western Power is listed as an additional insured.

1336. We recommend an amendment be made to the ETAC so that clause 21.3 reflects actual practice. We consider this would benefit both Western Power and the users.

1337. The amended clause 21.3 in Appendix A to the revised proposed access arrangement is as follows:

> In respect of the insurances referred to in Schedule 5 Part 1 (a)(i) (public and products liability insurance) and Schedule 5 Part 1 (a)(iv) (contractors' plant and equipment insurance) the insurance must list Western Power as an additional insured. ~~be:~~
>
> ~~(g) effected in the joint names of the Parties; or~~
>
> ~~(h) Western Power must be endorsed on the policies referred to in Schedule 5 Part 1 and the User must be indorsed on the policies referred to in Schedule 5 Part 1,~~
>
> ~~for their respective rights and interests~~.

18. Applications and Queueing Policy

1338. The ERA requires 20 amendments to the Applications and Queueing Policy (AQP). This section details Western Power's response to each required amendment to the AQP in turn.

1339. The revised AQP, which reflects the various amendments in response to the ERA's draft decision, is attached at Appendix B of the revised proposed access arrangement (Revised AQP).

18.1 Proposed amendments to connection application provisions

18.1.1 Dormant applications (ID 2)

ERA required amendment 62:

Clause 22 of the applications and queuing policy, covering provisions for dormant applications, must be amended in accordance with paragraph 1507 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1340. In its draft decision, the ERA requires that the time period in the proposed definition of 'dormant application' and clause 22(e)(ii) must be changed to three years to be consistent with the Model AQP.[312] It is unclear from paragraph 1507 whether the ERA requires that both the definition of 'dormant application' and clause 22(e)(ii) be amended to refer to three years or whether the time periods in the definition and clause 22(e)(ii) should add up to three years.

1341. Currently, it would appear the cumulative effect of the required amendment would prevent the deemed withdrawal of dormant applications for up to six years. Regardless, we consider the time periods in the 'dormant application' definition and clause 22(e)(ii) should both be 12 months, resulting in a cumulative period for up to two years before an application can be deemed withdrawn, for the reasons outlined below.

1342. While regard should be had to clauses A2.78 to A2.80 of the Model AQP in considering Western Power's proposed new clause 22, the differences between the process for withdrawing dormant applications described in clauses A2.78 to A2.80 and the process for withdrawing dormant applications described in Western Power's proposed new clause 22 must be appreciated.

1343. Under clauses A2.78 to A2.80 of the Model AQP, after an application has been in the queue for three years and Western Power considers it unlikely that an access offer will be made, Western Power may issue a 'show cause' notice to the applicant asking them to demonstrate why the application should not be deemed to be withdrawn. Western Power then has discretion to determine whether the application should be deemed to be withdrawn, based on the applicant's response to the 'show cause' notice. The three year time line in the Model AQP relates only to the age of the application, not the period of inactivity by the applicant.

312 Paragraph 1507, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

1344. Western Power's proposed new clause 22 improves upon the process in the Model AQP because:

- it is solely premised on the inactivity of applications, not their age (a five-year application that has involved processing activity in the last 12 months would not be captured), which is more aligned with the intent of the provision and less arbitrary in its effect
- it reduces Western Power's discretion by linking withdrawal outcomes to objectively identified events, and renders outcomes more predictable and transparent for applicants, consistent with sections 5.7(b) and 5.7(c) of the Access Code
- once clause 22 is engaged, Western Power is able to more proactively engage with dormant applicants to stimulate progress, and to place greater control over the outcome in the hands of applicants
- the 12-month time periods and process proposed are more aligned with the broader needs of all applicants (as reflected in stakeholder consultations) in both understanding how the AQP will operate and focusing Western Power's resources and processing activities on those applications genuinely intending to proceed
- when considered in combination with clause 2.4(c) of the AQP, the actual effect of the provision on pre-existing applications will be deferred for at least 12 months after the effective date of the AA4 revisions. This will allow sufficient notice for applicants who have not progressed their applications to do so. If dormant applications are not progressed during the 12 months after the AA4 revisions take effect, it will mean the true period of inactivity is likely to be much greater than 12 months in any event.

1345. In these circumstances, we consider the 12 month periods in the 'dormant application' definition and clause 22(e)(ii) are reasonable and justified in the context of the Access Code and the AQP.

1346. If the ERA intends that the time periods in the 'dormant application' definition and clause 22(e)(ii) should add up to three years cumulatively, it is worth noting that the cumulative two years under our original proposed amendment is not significantly less than three years, and is in fact longer than the time periods for the dormancy provisions that applied during the AA1 and AA2 periods, which the ERA approved under the Access Code.

1347. The AA1 and AA2 AQPs contained similar provisions to clauses A2.78 to A2.80 of the Model AQP, however, the definition of 'dormant application' referred to 12 months, not three years. As noted above, the 'two-year' period proposed by Western Power is likely in most cases to apply to applications that are older than two years as the relevant trigger is inactivity, not the age of the application. The effect of clause 2.4(c) of the AQP defers its application to existing applicants in any event.

1348. If the ERA intends the time period in clause 22(e)(ii) should be three years, in addition to the three years preceding the issuing of a notice under clause 22(a) (resulting in a cumulative effect of six years), this will prevent Western Power's use of clause 22 for the entirety of the AA4 period and render the mechanism practically redundant. This is because:

- clause 2.4(c) of the AQP delays the application of the provision until AA4 is effective, after which the initial period of three years starts to run before an application is considered to be dormant and notice can be given
- the three-year period under clause 22(e)(ii) (after notice is given under clause 22(a)) needs to lapse with no access contract being entered into during that period before an application is deemed to have been withdrawn.

1349. During our AQP consultations, the feedback in relation to the reintroduction of dormancy provisions has been positive. The existence of dormant applications affects Western Power's network management functions and can create difficulties for network planning. It also causes unnecessary uncertainty and delay to active applications. Where a dormant application is competing with other applications, Western Power is required to notify the dormant applicant of relevant applicant-specific solutions and to consider the dormant application for inclusion in competing application groups. This requires the use of Western Power's time and resources and can impact other applicants genuinely wishing to progress.

1350. We consider the effect of the required amendment relating to the time periods in the 'dormant application' definition and clause 22(e)(ii) (whether three or six years) would:

- be unlikely to have any beneficial outcomes during the AA4 period for applicants genuinely looking to progress a connection to the network
- do little to alleviate the concerns of applicants generally and other stakeholders regarding non-progressing applications
- require Western Power to continue to expend resources in seeking to stimulate non-progressing applications.

1351. We consider the position in our AA4 proposal is consistent with sections 5.7(b) and 5.7(c) of the Access Code. Specifically, the AA4 proposal allows a reasonable timeframe for the progression of applications and encourages applicants to seek to progress their applications.

1352. If the ERA is proposing a maximum six year timeframe for dormant applications to be withdrawn (which runs from the AA4 start date), we consider such an approach is contrary to the intent of sections 5.7(a) and 5.7(c) of the Access Code, and the Access Code objective. Such an approach does not balance the interests of all applicants and Western Power, nor does it reflect a reasonable timeframe for progressing applications. To the extent that dormant applicants can hold back or otherwise delay the progression of other applicants for significant periods of time, this undermines economically efficient investment in the network.

1353. We therefore consider the time periods in the 'dormant application' definition and clause 22(e)(ii) should both be 12 months. At the very least, we consider the 'dormant definition' application and clause 22(e)(ii) should not exceed three-years when added together, and that clause 2.4(c) should be qualified so that the initial time period for dormancy runs from the date of the application, not the effective date of the access arrangement.

1354. We accept the required amendment to change 'may' to 'will' in relation to giving a notice in clause 22(a), although we note the Model AQP does not include equivalent mandatory language regarding the initiation of the dormancy process.

1355. We do not accept the required amendment to limit Western Power's ability to issue a notice under clause 22(a) if the applicant's failure to undertake any processing activity in the period of time specified in the 'dormant application' definition is due to Western Power's material breach of the AQP or Western Power's negligence or default.

1356. We consider it reasonable to include some limitations on Western Power's ability to exercise its power under clause 22(a) following feedback received during the stakeholder consultation process, but consider that the required amendment to clause 22(b) goes beyond what is reasonably necessary and appropriate for the following reasons:

- Western Power already has overarching obligations to act reasonably, in good faith and to process applications expeditiously and diligently under clauses 3.1 and 3.12 of the AQP and the Access Code
- Western Power's use of the dormancy process in clauses A2.78 to A2.80 of the Model AQP is not limited by similar matters. Under those provisions, Western Power can issue a 'show cause' notice if Western Power "holds the opinion as a *reasonable and prudent person* that it is unlikely that an *access offer* will be made in respect of a *dormant application*". No explanation has been provided in the draft decision for materially departing from the standards imposed under the Model AQP in this way
- the limitations proposed by the required amendment in respect of Western Power exercising its powers under clause 22(a) are otherwise unprecedented under previous versions of the AQP and the Model AQP
- the introduction of a qualification of this nature renders the operation of the provision uncertain and unpredictable, and is otherwise unnecessary as applicants will have a fair opportunity to demonstrate the reasons why their application should not be deemed to be withdrawn
- the required amendment does not consider a situation where the applicant or a third party (e.g. other regulator) also contributes to the lack of processing activity in the relevant period
- the required amendment could lead to undesirable and counterproductive disputes brought by applicants regarding whether a material breach of the AQP has occurred and whether Western Power is at fault for the lack of processing activity in the relevant period.

1357. We therefore propose, as a preferable alternative to both the original AA4 proposal and the ERA's required amendment, to remove all references to fault and revert to the test adopted in the Model AQP that Western Power act as a 'reasonable and prudent person' in administering this provision.

1358. In relation to clause 22(d), we consider the wording 'upon Western Power's receipt of that response' is necessary to confirm the point in time at which the application is deemed to have been withdrawn. To avoid confusion, we propose a rearrangement of the wording within this clause.

1359. Western Power proposes an amended clause 22 in Appendix B to the revised proposed access arrangement incorporating the amendments set out above as follows:

(a) Subject to clause 22(b), Western Power ~~may~~ will give the *applicant* in respect of a *dormant application* a written notice requesting the *applicant* to show cause in writing why Western Power should continue to process the *dormant application*, and stating the work required to be completed to process the *dormant application*.

(b) In exercising its rights under this clause 22, Western Power must act as a *reasonable and prudent person*. ~~Western Power must not issue a notice under clause 22(a) if the failure to undertake any work or failure to agree any work to be undertaken within the relevant 12 month period, as the case may be, is solely due to Western Power's gross negligence or wilful default~~

(c) If an *applicant* does not respond to Western Power in writing within 20 business days of receipt of a notice under clause 22(a), the *dormant application*, and any associated *electricity transfer application*, shall be deemed to have been withdrawn and Western Power shall notify the *applicant* in writing accordingly.

(d) If an *applicant* responds to Western Power within 20 business days of receipt of a notice under clause 22(a) that it no longer wishes to progress the *dormant application* to an *access offer*, the *dormant application*, and any associated *electricity transfer application*, shall be deemed to have been withdrawn upon Western Power's receipt of that response. ~~A *dormant application*, and any associated *electricity transfer application*, shall also be deemed to have been withdrawn if the *applicant* responds to Western Power in writing within 20 business days of receipt of a notice under clause 22(a) that it no longer wishes to progress the *dormant application* to an *access offer*, upon Western Power's receipt of that response.~~

(e) If the *applicant* responds to Western Power within 20 business days of receipt of a notice under clause 22(a) contending that Western Power should continue to process the *dormant application*:

(i) Western Power must issue the *applicant* with a processing proposal under clauses 20.2, 20.3 or 24 as soon as practicable; and

(ii) if an *access contract* has not been entered into in respect of the *application* within 12 months of the date on which the notice under clause 22(a) was issued, Western Power may provide written notice to the *applicant* under this clause 22(e)(ii) of that fact upon which the *application*, and any associated *electricity transfer application*, shall be deemed to have been withdrawn under this applications and queuing policy.

(f) In issuing a notice under clause 22(e)(ii), Western Power must have regard to the objectives of this applications and queuing policy, the likelihood of the *application* progressing to an *access offer* and the existence of any *competing applications*.

18.1.2 Options for responding to preliminary access offers (ID 4)

ERA required amendment 63:

Clause 24.3(c) of the applications and queuing policy, dealing with an applicant's response to a notice of intention to respond to a preliminary access offer, must be amended to replace the word "may" with "will" in accordance with paragraph 1511 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1360. The ERA has proposed the following amendment to clause 24.3(c):

(c) advising that they wish to opt out of the *competing applications group* but that they do not want to make an *application* for an *applicant-specific solution* and wish to retain their *priority date* and be considered for inclusion in another *competing applications group*, in which case the *application* shall retain its *priority date* and ~~may~~will be considered for inclusion in another *competing applications group* in accordance with clause 24.1(a);

1361. Western Power accepts this amendment to clause 24.3(c) and has made the necessary change in the Revised AQP attached at Appendix B of the revised proposed access arrangement.

ERA required amendment 64:

Clause 24.5 of the applications and queuing policy, dealing with an applicant's response to a preliminary access offer, must be amended in accordance with paragraph 1515 of this Draft Decision to:

- clarify that the 30 business days commence after the receipt of the notice (clause 24(a)(ii)); and
- replace the word "may" with "will" (clause 24.5(a)(ii)(B)).

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1362. The ERA has proposed the following amendments to clause 24.5(a) and 24.5(a)(ii):

(a) *Applicants* must respond to the *preliminary access offers* within 30 business days after ~~of~~ receipt of the *preliminary access offers*, by indicating in good faith in writing either:

.....

(ii) … but if Western Power and the *applicant* have not agreed on the form of the *preliminary access offer* within 30 business days ~~of~~ from the date on which the *applicant* received the *preliminary access offer*, then the application…

1363. The ERA has proposed the following amendment to the clause 24.5(a)(ii)(B):

(B) the *applicant* has notified Western Power in writing that it wishes to opt out of the *competing applications group* but it does not want to make an *application* for an *applicant-specific solution* and wishes to retain its *priority date* and be considered for inclusion in another *competing applications group*, in which case the *application* shall retain its *priority date* and ~~may~~ will be considered for inclusion in another *competing applications group* in accordance with clause 24.1(a); or

1364. Western Power accepts each of the above amendments to clause 24.5 and has made the necessary changes in the Revised AQP attached at Appendix B of the revised proposed access arrangement.

18.1.3 Funding studies to prepare a notice of intention (ID 5)

ERA required amendment 65:

Clause 20.2(a)(i) of the applications and queuing policy must be amended to read:

"Western Power must provide a proposal within a reasonable time to the applicant outlining the scope, timing and good faith estimate …"

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1365. The ERA has proposed the following amendment to clause 20.2(a)(i):

(i) Western Power must provide a proposal within a reasonable time to the applicant outlining the scope, timing and a good faith estimate …

1366. Western Power accepts in principle that it needs to progress its obligations within clause 20.2(a)(i) in a timely manner but considers that the inclusion of the words 'within a reasonable time' in clause 20.2(a)(i) is unnecessary to achieve this outcome for the following reasons:

- Western Power already has overarching obligations to act reasonably and to process applications expeditiously and diligently under clauses 3.1 and 3.12 of the AQP and under the Access Code – these types of obligations do not need to be restated throughout the AQP
- given clause 3.12 of the AQP requires Western Power to perform the obligations under clause 20.2(a)(i) expeditiously it is unclear and uncertain what it then means to perform the same obligations within a reasonable time. It is also unclear as to when the 'reasonable time' commences.

1367. Western Power has not included the proposed amendment in the Revised AQP on the basis that the overarching obligations in clauses 3.1 and 3.12 of the AQP apply to ensure Western Power progresses its obligations in clause 20.2(a)(i) in a timely manner.

18.1.4 Forecast natural load growth considerations (ID 6)

ERA required amendment 66:

The proposed amendments to include forecast natural load growth in the definition of spare capacity and clause 24.8(a) of the applications and queuing policy must be deleted.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

1368. Western Power does not accept that no amendments should be made to the definition of spare capacity or to clauses 3.15(d) and 24.8(a) to capture forecast natural load growth as being relevant to assessing spare capacity.

1369. The concept of 'spare capacity' is fundamental to the AQP and the processing of applications. There should be clarity within the AQP regarding the relevance of forecast natural load growth to the processing of applications.

1370. As acknowledged by the ERA in its draft decision, forecast natural load growth should be taken into account by Western Power when undertaking its network planning activities.[313] Forecast natural load growth represents what Western Power expects to receive in the future based on reliable predictions of a number of factors including population, industry and demand growth. While clause 3.15(d) of the AA3 AQP only expressly refers to applications being a relevant factor for Western Power when undertaking network planning, the practical reality is that network planning, including assessments of forecast natural load growth, also affects how Western Power processes applications.

1371. We consider forecast natural load growth is essential to assessing spare capacity on the network and operating the network in an economically efficient manner, consistent with the Access Code objective and in accordance with good electricity industry practice, as required by clause 1.8.1(a)(4) of the Technical Rules. Further, in considering access arrangements under section 4.30 of the Access Code, the ERA is to have regard to the operational and technical requirements necessary for the safe and reliable operation of the network. We consider factoring forecast natural load growth into assessments of spare capacity is necessary for ensuring such safe and reliable operation of the network.

1372. We also note section 14.3 of the Access Code requires Western Power to determine the spare capacity within the transmission system annually as a reasonable and prudent person, being a person acting in good faith and in accordance with good electricity industry practice. Good faith and good electricity industry practice requires Western Power to take into account forecast natural load growth when assessing applications to connect to the network and the capacity that may be available. The definition of good electricity industry practice in section 1.3 of the Access Code refers to the foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances.

1373. The ERA's comment that it would be contrary to the Access Code objective for Western Power to leave capacity unutilised on the basis that it may one day be required does not accurately reflect the rigour with which Western Power assesses factors such as load growth in its network planning activities. Western Power is not seeking to deprive applicants of access to this capacity, but rather ensure capacity exists for existing customers who may increase their load (e.g. small use customers purchasing larger appliances TV or more re-chargeable devices) or new loads arising from new subdivisions and urban infill as part of WA Planning Commission processes.

1374. An understanding of how forecast natural load growth is relevant to the processing of applications is obtained from considering an example of a substation (which has a limited capacity) built to facilitate greenfields subdivisions in the surrounding area or which services an area undergoing considerable infill development. Western Power needs to have regard to the impact of the natural load growth from these new subdivisions/developments on spare capacity rather than making the majority or all such capacity available to one connection applicant. If the latter occurred it would effectively stifle further subdivision/infill developments in the area for the period of time until a new substation could be built.

1375. Western Power therefore maintains the necessity of the amendments to the definition of spare capacity and clauses 3.15(d) and 24.8(a) of the AQP put forward in its AA4 proposal. These amendments are required in the interests of transparency and predictability regarding the assessment of spare capacity and some of the relevant factors considered by Western Power.

[313] Paragraph 1530, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

1376. However, we propose to insert the test of 'acting as a *reasonable and prudent person'* to qualify the class of considerations that might be taken into account in assessing spare capacity within clauses 3.15(d) and 24.8(a). To implement this Western Power proposes amendments to clause 3.15(d) in the Revised AQP as follows:

(d) In undertaking network planning Western Power, acting as a *reasonable and prudent person,* will have regard to matters including forecast natural load growth and the nature and number of *enquiries* and *applications* Western Power has received under this applications and queuing policy, it being acknowledged that in doing so Western Power will need to make a good faith assessment as to the likelihood that specific projects will proceed.

1377. Western Power also proposes amendments to clause 24.8(a) in the Revised AQP as follows:

(a) In determining whether there is *spare capacity* to provide *covered services* requested in a *connection application* or group of *applications*, Western Power, acting as a *reasonable and prudent person,* may have regard to matters including forecast natural load growth and must assume that any existing *access contract* will be renewed in accordance with the terms of that *access contract.*

18.1.5 Studies for applicant-specific solutions (ID 8A)

ERA required amendment 67:

Clause 24.1(c) of the applications and queuing policy must be amended as follows to make it consistent with other clauses in the policy:

" … and the applicant will be deemed to have made a request for~~requested~~ a study under clause 20.3(a)."

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1378. The ERA has proposed the following amendment to the clause 24.1(c):

(c) To the extent necessary to allow:

(i) a supplier of last resort (as defined in section 67 of the *Act*) to comply with its obligations under Part 5 of the *Act*; or

(ii) a default supplier (as defined in section 59 of the *Act*) to comply with its obligations under section 59 of the *Act*,

an *applicant* may advise Western Power at any time that it does not wish to be considered to be included within a *competing applications group,* in which case it will be treated as having made an *application* for an *applicant-specific solution* and the *applicant's connection application* will be processed as an *applicant-specific solution* in accordance with clauses 19 and 20 (and the other relevant provisions) of this applications and queuing policy and the *applicant* will be deemed to have made a request for ~~requested~~ a study under clause 20.3(a).

1379. Western Power accepts this amendment to clause 24.1(c) and has made the necessary change in the Revised AQP attached at Appendix B of the revised proposed access arrangement.

18.1.6 Mandatory preliminary assessments (ID 9)

ERA required amendment 68:

Clauses 18.1 and 19.1 of the applications and queuing policy, setting out provisions for a preliminary assessment and initial response, must be amended in accordance with paragraph 1554 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1380. The ERA has proposed the following amendment to clause 18.1 and 19.1:

18.1 Compulsory Enquiry Notification

(a) Where an applicant expects, in good faith, to proceed to a connection application, then prior to lodging a connection application with Western Power, the applicant:

(i) must lodge an enquiry with Western Power to notify Western Power of the proposed connection application; and

(ii) may request that a preliminary assessment is undertaken under clause 19.3 prior to the applicant ~~to occur before~~ lodging the ~~proposed~~ connection application.

(b) In the event of an enquiry under clause 18.1(a)(i) or a request under clause 18.1(a)(ii) Western Power must engage in such discussions with the applicant in good faith and ...

19.1 Initial Response

(a) Subject to clause 19.1(b), Western Power … specifying:

(i) the time by which Western Power will provide a preliminary assessment under clause 19.3 of~~with regards to~~ the connection application (if such an assessment was not provided~~undertaken~~ under clause 18.1 before the *connection application* was submitted~~and is required under clause 19.3~~); and

1381. Western Power accepts the amendments to clauses 18.1(a) and 19.1(a), save that the words '*and is required under clause 19.3*' should be retained in clause 19.1(a).

1382. A preliminary assessment will not be required if Western Power and the applicant agree to that effect under clause 19.3. Removing the wording '*and is required under clause 19.3*' from clause 19.1(a) creates a mandatory obligation for Western Power to advise the applicant when a preliminary assessment will be provided if one was not completed before the application was lodged, even where Western Power and the applicant may have already agreed that such an assessment is not required.

1383. Therefore, the wording '*and is required under clause 19.3'* is necessary within clause 19.1(a) to reflect that a preliminary assessment may not always be required in accordance with clause 19.3.

1384. Western Power has revised the amendment to clause 19.1 set out in the ERA's draft decision in its Revised Proposal as follows:

> 19.1 Initial Response
>
> (a) Subject to clause 19.1(b), Western Power … specifying:
>
> (i) the time by which Western Power will provide a preliminary assessment under clause 19.3 of the connection application (if such an assessment was not provided under clause 18.1 before the connection application was submitted <u>and is required under clause 19.3</u>); and

18.1.7 Payment of fees and contributions policy (ID 22)

ERA required amendment 69:

Clause 24.3(a) of the applications and queuing policy must be amended in accordance with paragraph 1577 of this Draft Decision to include the words: "and where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract".

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1385. The ERA has proposed the following amendment to clause 24.3(a):

> (b) agreeing to have their *application* considered within a *competing applications group* and paying the preliminary offer processing fee as specified in the *price list*. By paying the preliminary offer processing fee, *applicants* demonstrate the good faith of their intention to proceed to an *access contract*, and as such the preliminary offer processing fee is non-refundable. Where the *applicant* subsequently enters an *access contract*, the preliminary offer processing fee will be counted towards any contribution payable, where permissible under the contributions policy <u>and where it exceeds any *contribution* payable under the *contributions policy*, the excess will be offset against any amounts payable under that *access contract*</u>; or

1386. We do not accept the reinstatement of the wording '*and where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract*' in clause 24.3(a) for several reasons:

- These words, in effect, provide that amounts that would not be counted towards contributions in accordance with the contributions policy should in any case be offset against other amounts payable under an access contract. Applicants who are not undertaking processing through a competing applications group (e.g. those who are not competing or who are not competing applications group members, and whose applications are processed solely pursuant to clauses 20.2 or 20.3) do not receive such an offset, and no such additional offset is required under the Model AQP.
- The removal of the wording as proposed in Western Power's AA4 original proposal ensures the contributions policy operates as it ordinarily would, without seeking to supplement or change its effect. To treat different applicants differently based on whether they are part of a competing

applications group or not would be inconsistent with Western Power's obligations to act in a non-discriminatory manner under the Access Code, and would run contrary to the effect of the contributions policy.

- The words '*where it exceeds…the excess will be offset*' also fails to distinguish between those portions of the preliminary offer processing fee that comprise amounts that could be counted towards contributions, and those portions of the preliminary offer processing fee that comprise the costs of Western Power in processing the competing applications group, including communication with participants, the negotiation of agreements, the preparation of Notice of Intention to Prepare a Preliminary Access Offers (NOI), Preliminary Access Offers (PAO) and Access Offers. These latter portions represent a fee paid for a service provided and are necessary to ensure that Western Power is able to recover its costs. It would not be appropriate for Western Power to have to, in effect, refund such portions of the preliminary offer processing fee in any circumstances, but particularly to those who ultimately receive the benefit of that processing by entering into an access contract.

- The words '*offset against amounts payable under that access contract*' does not recognise that in the majority of cases, the applicant will not be the party to the access contract with Western Power under which access charges are payable. Western Power notes than unless the applicant is a large generator it is unusual for the applicant to be a party to the access contract. Western Power does not consider it appropriate to provide the party with the access contract the offset who may then be under no obligation to pass that offset on to the applicant. The contributions policy does not contemplate the offsetting of a payment made by one party against payment required from another party. Consequently, if the applicant is in most cases not party to the access contract, they could not secure the benefit of the offset in any event.

- While Western Power notes the wording previously formed part of this provision, we have since become aware of its unintended consequences and submit that it is not compatible with the operation of the AQP and the contributions policy in a non-discriminatory manner and therefore should not remain.

1387. The remaining words '*Where the applicant subsequently enters an access contract, the preliminary offer processing fee will be counted towards any contribution payable, where permissible under the contributions policy*' merely states what would apply in any case for clarification purposes. If an applicant has paid a sum which the contributions policy requires be taken into account in determining a contribution payable, Western Power would do so even if this wording were not included.

1388. Western Power has not made any further changes to the Revised AQP in relation to this required amendment.

18.1.8 Payment of fees and contributions policy (ID 23)

ERA required amendment 70:

Clause 24.5(b) of the applications and queuing policy must be amended in accordance with paragraph 1582 of this Draft Decision to include the words: "and where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract".

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1389. Western Power does not accept the required amendment to clause 24.5(b) as proposed in the ERA's draft decision for the same reasons as Western Power does not accept the amendments to clause 24.3(a) of the AQP except those reasons apply to clause 24.5(b) of the AQP rather than clause 24.3(a).

1390. Western Power has not made any further changes to the Revised AQP in relation to this required amendment.

18.2 Proposed amendments to transfer application provisions

18.2.1 Contestable customers (ID 14)

ERA required amendment 71:

Clause 13.3 of the applications and queuing policy, requiring Western Power to reject an application where the customer is not a contestable customer, must be amended in accordance with paragraph 1603 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1391. The ERA has proposed the following amendment to clause 13.3:

13.3 Rejection of Application

Western Power must reject an application where it ~~Where Western Power~~ is not authorised under the Electricity Corporations Act 2005 or other written law to make an access offer ~~for an application~~ for the purpose of the supply of electricity to a customer because that customer is not a contestable customer~~, Western Power must reject the application~~.

1392. We accept this amendment and have made the necessary changes in the Revised AQP attached at Appendix B of the revised proposed access arrangement.

18.2.2 Relationship with transfer and relocation policy (ID 15 and 15A)

ERA required amendment 72:

Proposed new clause 12A ("Relationship with transfer and relocation policy") must be deleted from the applications and queuing policy.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

1393. The ERA has proposed to delete the following clause 12A which was proposed as a new clause in the AQP by Western Power:

> 12A Relationship with transfer and relocation policy
>
> (a) The transfer and relocation policy applies to bare transfers, and assignments other than bare transfers, of rights under an access contract. To avoid doubt, this applications and queuing policy does not apply to applications for such transfers or assignments, including temporary transfers or assignments.
>
> (b) If a user seeks a relocation under the transfer and relocation policy, it must make an electricity transfer application under this applications and queuing policy by notice in writing to Western Power.
>
> (c) If a relocation the subject of an electricity transfer application under clause 12A(b):
>
> (i) requires an augmentation or any work to be completed to enable the increase or decrease in contracted capacity at the relevant connection point; or
>
> (ii) would result in Western Power's ability to provide a covered service to another user or applicant who has lodged a connection application being impeded,
>
> then the applicant must submit a connection application and the requirements of that application must be satisfied before the relocation can occur.

1394. We do not accept this amendment as we believe there is a requirement (as highlighted in paragraph 1845 of the ERA's draft decision) to consider the relevance of the AQP when considering a relocation request. However, we will accept the deletion of the proposed AQP clause 12A if amendments to the AQP that achieve the same effect as clause 12A in respect to relocations are made elsewhere in the AQP.

1395. In summary:

- we accept the deletion of proposed new clause 12A(a) seeking to confirm that the AQP does not apply to bare transfers and assignments.
- we accept the deletion of new clauses 12A(b) and 12A(c), subject to amendments being made to clauses 10.2(a), 16.2(a), 16.3 and 16.4 to refer to applications being made if a relocation requires modifications to generating plant, or works or augmentations to the network.

1396. The ERA's draft decision regarding the Transfer and Relocation Policy states:

> *Given the constrained nature of the Western Power Network, relocations can only occur when there is available capacity at the destination point. Where capacity is unavailable, or there are multiple requests for capacity at a particular connection point, Western Power must consider its applications and queuing policy to process the relocation request(s). The proposed new clause 6.3 [of the TaRP] reflects the process and procedures Western Power must consider when accessing a relocation request.*[314]

1397. We consider the new clause 12A proposed by Western Power in its original AA4 proposal and currently proposed amendments to clauses 10.2(a), 16.2(a), 16.3 and 16.4 are consistent with and seek to address the issues set out in the ERA's comments in paragraph 1845 regarding the relevance of the AQP in processing relocation requests. Relocations can require modifications to generating plant and other works to ensure technical compliance.

1398. We also note that relocations require modifications to an access contract (i.e. to reduce capacity at one connection point and make a corresponding increase to capacity at another connection point under the same access contract), which is effected by way of an electricity transfer application and, in some cases, a connection application. Where a relocation requires works or augmentations, a connection application is required to enable Western Power to facilitate those works and ensure that network safety, reliability and security is not compromised, and other applicants and existing network users are not impeded.

1399. Therefore, it is beneficial for the AQP to confirm that connection applications are required where a relocation requires works or augmentations, or would result in an existing user or other applicant being impeded. This would ensure the AQP explains how it will operate in the circumstances of relocations for the purposes of section 5.7(b) of the Access Code.

1400. The amendments Western Power proposes to the Revised AQP are as follows:

Clause 10.2(a)

(a) An *electricity transfer application* to increase or decrease *contracted capacity* with respect to an existing *covered service* under the *applicant's access contract*, including as required for a *relocation*, may be made by notice to Western Power.

Clause 16.2(a)

(a) If, after processing an *electricity transfer application* under clause 10.2, Western Power requires a *connection application*, including in relation to a *relocation*, then the *user* must submit or, if applicable, procure that its *customer* submits, a *connection application* on the *connection application form* that is applicable for the type of *facilities and equipment* that is *connected* at the *connection point*.

Clause 16.3

If an *applicant* seeks to materially change the characteristics of *generating plant connected* at a *connection point*, including in relation to a *relocation*, then the *applicant* must complete those parts of the appropriate *application form* that deal with those characteristics, and include any additional information specified in the *application form* (which might include equipment schedules, drawings and computer models) that Western Power, as a reasonable and prudent person, might require to assess the impact of the modification on the *network* and other *users*, and compliance of the modified *generating plant* with the *technical rules*.

314 Paragraph 1845, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

Clause 16.4

An *applicant* who seeks to modify or *augment* the *network* for the purpose of receiving a *covered service*, including in relation to a *relocation*, other than under clause 16.1 must submit a *connection application* on the applicable *connection application form*.

18.2.3 Covered services (ID 18)

ERA required amendment 73:

The definition of "connection application" (at clause 2.1) in the applications and queuing policy must be amended in accordance with paragraph 1631 of this Draft Decision to add the words *"in a way that means they no longer meet the eligibility criteria".*

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1401. The ERA has proposed the following amendment to part (c) of the definition of 'connection application' (within clause 2.1) as follows:

> (c) materially modify *facilities and equipment connected* at an existing *connection point* in a way that means that they no longer meet the eligibility criteria;

1402. We accept the required amendment to paragraph (c) of the definition of 'connection application', subject to:

- the wording 'for the *covered service* provided at the relevant *connection point*' being inserted after 'in a way that means they no longer meet the eligibility criteria' for further clarity. As the AQP does not otherwise contain any provisions relating to eligibility criteria, the meaning of the reference to 'eligibility criteria' would be unclear without this additional wording.
- inserting at the end of that paragraph wording to make clear the paragraph also applies if the modification 'is likely to adversely impact the security, safety or reliability of the network' as a connection application has always been, and will continue to be, necessary, in such cases. Paragraph (c) of the 'connection application' definition should not be limited to exclude such a trigger for a connection application.

1403. Western Power proposes a revised part (c) of the definition of 'connection application' (at clause 2.1) in the Revised AQP attached at Appendix B of the revised proposed access arrangement as follows:

> (c) materially modify *facilities and equipment connected* at an existing *connection point* in a way that means that they no longer meet the eligibility criteria for the *covered service* at the relevant *connection point* or if the modification is likely to adversely impact the security, safety or reliability of the *network*;

18.2.4 Confidentiality (ID 19)

ERA required amendment 74:

Proposed amendments to clause 6.2(a) of the applications and queuing policy, which allows the disclosure of confidential information to the market operator or where necessary for the performance of Western Power's functions, must be deleted.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1404. The ERA has proposed the following amendment to clause 6.2(a):

Western Power, an *applicant* or a *disclosing person* must not disclose *confidential information* unless:

(a) the disclosure is made on a confidential basis~~:~~

~~(i)~~ to the *Authority*.~~; or~~

~~(ii) to the *market operator*; or~~

~~(iii) where necessary for the performance of Western Power's functions; or~~

1405. We accept the required amendment to delete '*where necessary for the performance of Western Power's functions'* within clause 6.2(a). However, we propose the other amendments in the AA4 proposal be retained and clarified.

1406. Western Power is often required to disclose information relating to applications to the AEMO (both in its capacity as market operator and as system management) when developing solutions that seek to connect applicants to the network (for example, the generator interim access solution).

1407. As the system management function is now performed by the AEMO, it is particularly important for Western Power to be able to more freely share and discuss information about applications with the AEMO to ensure that system security, safety and reliability will not be adversely affected by new or modified connections and services.

1408. In the context of a constrained network and the development and operation of constrained access solutions, there is an increased need for Western Power to provide information about applications to the AEMO for these purposes. The Technical Rules also require Western Power to consult with system management about matters including Technical Rule exemptions (e.g. clause 1.9.1(b) of the Technical Rules) which applicants often seek.

1409. Since the AA3 AQP was introduced, the system management function moved from a segregated business unit within Western Power to the AEMO. Therefore, the need for Western Power to share information with the AEMO (in its capacity as system management) about applications has not been as significant as it is now.

1410. For these reasons, we consider disclosure of confidential information about applications to the AEMO (both in its capacity as market operator and system management) is necessary for Western Power and the AEMO to effectively perform their functions. The proposed drafting in the Revised AQP requires that the disclosure be made on a confidential basis in any case.

1411. Further, Western Power does not consider the existing definition of 'market operator' was sufficiently clear to encompass AEMO in its system management capacity. As set out above, solutions need to be discussed with AEMO both in its capacity as market operator and in its capacity as system management. As such, Western Power considers it important to clarify this.

1412. Western Power proposes to amend clause 6.2(a) in the Revised AQP as follows:

> Western Power, an *applicant* or a *disclosing person* must not disclose *confidential information* unless:
>
> (a) the disclosure is made on a confidential basis:
>
> (i) to the *Authority*;
>
> (ii) to the *market operator*; or
>
> (iii) to *system management*;
>
> ~~(iv) where necessary for the performance of Western Power's functions; or~~

1413. Western Power proposes to amend the existing definition of 'market operator' in the Revised AQP (within clause 2.1) as follows:

> "**Market Operator**" means the entity conferred the functions in respect of the 'Wholesale Electricity Market' under the WEM Rules ~~has the meaning given to the term 'operator' in the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*~~, which, as at the date this version of the applications and queuing policy comes into effect, is the Australian Energy Market Operator Limited.

1414. Western Power proposes to include a new definition of 'system management' in the Revised AQP (within clause 2.1) as follows:

> "**System Management**" means the entity conferred the functions in respect of 'System Management' under the WEM Rules which, as at the date this version of the applications and queuing policy comes into effect, is the Australian Energy Market Operator Limited.

ERA required amendment 75:

Clause 24.9(d) of the applications and queuing policy must be amended in accordance with paragraph 1644 of this Draft Decision to provide that Western Power must not make known confidential information under the clause if it is possible from the anonymised information to determine the identity of the competing connection applicant.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

1415. The ERA has proposed the following amendment to clause 24.9(d):

> Western Power must not make known confidential information under this clause if it is possible from the anonymised information to determine the identity of the competing connection applicant.

1416. If implemented, the required amendment effectively prevents Western Power from sharing with competing applicants, within and outside competing applications groups, critical information they require to make informed decisions about whether to proceed with their connection application and/or whether to participate in a competing applications group. The anonymised information set out in clause 24.9(d) is necessary for applicants to properly assess matters such as:

- their likelihood of connecting the network
- their priority date relative to other applications affected by the same constraints
- the level of constraint which may affect them if connected to the network
- the times of day when they may be able to access the network
- the works and augmentations Western Power advises are necessary to connect the applicant to the network.

1417. We consider the ability to act reasonably and in good faith in processing applications will be compromised if information applicants legitimately require in order to make informed decisions and to effectively negotiate with Western Power, cannot be disclosed.

1418. The required amendment is impractical because Western Power cannot know whether it is possible for another applicant to determine the identity of a competing applicant from anonymised information. Western Power is not and cannot be fully aware of every connection applicant's knowledge about every other competing connection application, or whether a particular applicant is able to use their industry knowledge combined with the anonymised information to determine identity. Indeed, in that context, it would always be 'possible' for identity to be determined.

1419. The required amendment therefore imposes an unacceptable risk to Western Power of innocently and unknowingly breaching clause 24.9, a risk that Western Power cannot effectively manage or mitigate. The information an applicant puts into the public domain about its project could lead to another applicant being able to identify the applicant's project from anonymised information.

1420. Western Power and other competing applicants have no control over the type and level of information which another applicant puts into the public domain about that applicant's project. By adopting the required amendment, Western Power would either be effectively prevented from using the provision or would run the risk of access disputes initiated by applicants alleging Western Power has failed to comply with the AQP.

1421. We consider an applicant who chooses to put information about its project into the public domain must accept the risk that doing so could increase the likelihood of competing applicants identifying the applicant's project from anonymised information. It is easier and more reasonable for applicants to modify or adapt their behaviours in this respect than for Western Power to withhold anonymised information from competing applicants who have a legitimate need to consider that information when making decisions about their applications.

1422. From our experience, we consider the required amendment is inconsistent with the wishes of the majority of applicants. Western Power receives frequent requests from applicants for information about competing applications in the nature of that set out in clause 24.9(d). Accordingly, we consider that the required amendment to clause 24.9(d) does not satisfy the Access Code requirement in:

- section 5.7(a), as it fails to balance the interests of all applicants and Western Power to the extent reasonably practicable
- section 5.7(d), as it could effectively prevent Western Power from providing an applicant with technical and commercial information requested to enable the applicant to engage in effective

negotiation with Western Power regarding the terms for an access contract, including as to the availability of covered services on the network.

1423. The best that can be done by Western Power in the interests of balancing the rights of all applicants and the need to efficiently process applications is to provide anonymised information of the nature set out in Western Power's proposed amendments.

1424. We also consider any requirements in the Access Code relating to reasonable confidentiality requirements must be considered in the context of a constrained network where having information about competing applications is reasonably necessary to make informed decisions and negotiate effectively. In such circumstances, the disclosure of clearly identified anonymised information is reasonable and should not be limited as proposed by the ERA's required amendment.

1425. Western Power has not made any further changes to the Revised AQP in relation to this required amendment.

18.2.5 Conditions precedent (ID 24)

ERA required amendment 76:

Clause 4.8 of the applications and queuing policy, containing provisions for conditions precedent, must be amended in accordance with paragraph 1660 of this Draft Decision to:

- set a fixed upper limit on the period allowed in sub-clause (a); and
- better link sub-clauses (a) and (b).

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1426. The ERA has proposed the following amendment to clause 4.8:

4.8 Conditions Precedent Not Longer Than 8 Months

(a) Western Power and an applicant must not enter into an access contract that contains a condition precedent ~~for which a period of longer than~~that may be fulfilled more than 8 months from the date the access contract was entered into ~~is allowed for its fulfilment~~, unless the applicant and Western Power agree that a longer period is reasonably necessary due to the nature of works to be conducted, in which case the period of 8 months may be extended by up to 4 months but the total time for fulfilment must not exceed 1 year~~, including due to the nature of works to be conducted~~.

(b) If, after 8 months or ~~such other~~after expiry of a longer period of time agreed under clause 4.8(a), a condition precedent in an access contract has not been fulfilled, then:

1427. We accept in part the required amendment to clauses 4.8(a) and 4.8(b), except that the upper limit for fulfilment of conditions precedent under the access contract should be limited to those to be fulfilled by the user.

1428. An upper limit of 12 months for a condition precedent relating to works to be completed by Western Power provides insufficient flexibility as large and complex connection works and shared network works may and do legitimately require a longer period to be completed. In such cases, the access contract should not become unconditional until those works are complete and the user is physically able to transfer electricity at the relevant connection point in accordance with the access contract.

1429. We note clauses A2.82 to A2.85 of the Model AQP do not impose any limits on the length of time for fulfilment of conditions precedent under an access contract. Rather, clause A2.85 provides that nothing in clause A2.84 (regarding conditions precedent and determining spare capacity) prevents a service provider or an applicant from entering into an access contract containing a condition precedent for which a period longer than 18 months from the date the access contract was entered into is allowed for its fulfilment. This is consistent with section 2.4A of the Access Code regarding freedom to contract and sections 2.7 and 2.8 concerning the accommodation of an applicant's requirements.

1430. Alternatively, if the ERA wishes to set an upper limit for fulfilment of conditions precedent to be fulfilled by Western Power, that upper limit should be no less than three years.

1431. Western Power proposes to revise clauses 4.8(a) and (b) as follows:

(a) Western Power and an *applicant* must not enter into an *access contract* that contains a condition precedent that may be fulfilled more ~~for which a period of longer~~ than 8 months from the date the *access contract* was entered into, unless the condition precedent relates to the completion of the related *works* and the applicant and Western Power agree that a longer period is reasonably necessary due to the nature of *works* to be conducted, in which case the period of 8 months may be extended by agreement between the *applicant* and *Western Power*. ~~including due to the nature of *works* to be conducted.~~

(b) If, after ~~8 months or such other after expiry of a longer~~ the period of time agreed under clause 4.8(a), a condition precedent in an *access contract* has not been fulfilled, then: …

18.3 Proposed amendments to support time of use tariffs and advanced metering (ID 27 to 31)

ERA required amendment 77:

The proposed amendments to support "time of use" tariffs and advanced metering (change identification numbers 27 to 31) must not be made to the applications and queuing policy.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1432. Western Power agrees not to amend the AQP to support time of use tariffs and advanced metering installations, however, we consider that some of the amendments relating to clauses 3.6 and 8 of the AQP should be retained as they are of broader beneficial use in the AQP and are not specifically related to time of use tariffs or advanced metering.

1433. Clause 8 relates to Western Power's ability to reject an application for a reference service where eligibility requirements for that reference service are not satisfied. It needs to be clear that this provision relates only to electricity transfer application made under Part B of the AQP. As such, the proposed amendment at clause 8 should be retained.

1434. An electricity transfer application should contain information about the applicant's eligibility for the covered service sought in the application and, where the application relates to a new connection point, any facilities and equipment likely or required to be connected at the connection point. As such, the proposed amendment at clause 3.6 has been retained in the Revised AQP attached at Appendix B of the revised proposed access arrangement.

18.4 Other minor amendments to the policy

18.4.1 Notes to defined terms (minor amendments 1 and 2)

ERA required amendment 78:

The definition of "Customer Transfer Code" in clause 2.1 of the applications and queuing policy must be amended to refer to the Electricity Industry Customer Transfer Code 2016 (and not the Electricity Industry Customer Transfer Code 2004).

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1435. Western Power accepts this amendment updating the reference from the 2004 version of the Electricity Industry Customer Transfer Code to the current 2016 version of the Code.

1436. Western Power has amended the definition of "Customer Transfer Code" in the Revised AQP (within clause 2.1) as follows:

> **"Customer Transfer Code"** means the *Electricity Industry Customer Transfer Code 2016* ~~*2004*~~, made under section 39(2)(a) of the *Act* in respect of the matter referred to in section 39(2)(b) of the *Act*, and includes all rules, policies or other subordinate documents developed under the *Customer Transfer Code*.

18.4.2 Drafting improvements (minor amendment 7)

ERA required amendment 79:

Clauses 3.15(a); 4.8(b)(i); 24.3(b); 24.5(a) and 24.6 of the applications and queuing policy should be amended to improve drafting clarity in accordance with paragraph 1679 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1437. Western Power accepts the principle behind this required amendment, in that it seeks to improve drafting clarity. We have accepted some of the ERA's recommended drafting improvements, but not all of them. The proposed minor amendments to each clause listed in required amendment 79 are discussed below.

1438. **Clause 3.15(a)** – we do not accept the required amendment to reinstate the word '*whether*' in place of '*including*'.

1439. As clause 3.15(a) is within Part A of the AQP, it applies to both connection and transfer applications. Transfer applications are not processed as applicant-specific solutions or within competing applications groups. Further, all connection applications are not processed as either applicant-specific solutions or within competing applications groups as some applications are assessed as not competing.

1440. The term '*applicant-specific solution*' has a specific meaning in the context of Part C of the AQP relevant to an application which has been assessed as competing with other applications and in respect of which the applicant has opted for an '*applicant-specific solution*'. The term does not include, nor refer to, non-competing applications. Therefore, we consider that '*including*' is the appropriate term for that relevant part of clause 3.15(a) and that '*whether*' could lead to confusion and misconceptions by applicants that all applications under the AQP have to be processed as either applicant-specific solutions or within competing application groups. Alternatively, we propose that all text within and including the parentheses be deleted.

1441. **Clause 4.8(b)(i)** – we do not accept the ERA's proposed change to reinstate '*conditions precedent*'.

1442. We agree there may be more than one condition precedent in an access contract. However, the first line of clause 4.8(b) refers to '*condition precedent*' in the singular and therefore the focus of clause 4.8(b) is a single '*condition precedent*'. The fact that Western Power and a user may agree to extend one condition precedent within an access contract does not mean Western Power and the user will agree to extend the due date for fulfilment any other condition precedent Western Power and the user may agree. If '*conditions precedent*' is reinstated in clause 4.8(b)(i), misconceptions could arise regarding the operation of the provision and whether it applies to all conditions precedent.

1443. **Clause 24.3(b)** – we accept the deletion of '*to*'.

1444. The ERA's draft decision appears to include an error in the third bullet point within paragraph 1679 which seeks to extract clause 24.3(b) and states *'advising that they do not wish to opt out of the competing applications group…' (emphasis added). We do not accept adding 'do not' to clause 24.3(b) as it would invert the intended meaning of the clause. We presume this is a drafting error*.

1445. **Clause 24.5(a)** – we accept the required amendment.

1446. **Clause 24.6** – we accept the required amendment to clause 24.6, but suggests that the words '*it will*' are also added to clause 24.6(b) for consistency.

1447. Western Power has made the necessary changes in the Revised AQP to reflect the positions described above.

18.4.3 Process overview (minor amendments 11 and 12)

ERA required amendment 80:

The applications and queuing policy must retain Figure 1 ("Access, Connection and Transfer Applications Policy – Process Overview").

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1448. We accept that an illustration of the processes described in the AQP may be useful to applicants, however, we consider the existing flowchart contained additional detail that was complex. Further, some of the information reflected internal processes that had become outdated. As such Western Power has amended Figure 1 by creating an alternative flowchart that provides a current high level overview of the transfer and connection application processes.

1449. We consider this new flowchart is easier to use, provides greater clarity as to the applications process and usefully directs readers to the relevant AQP provisions. As there is considerable overlap between the revised Figure 1 and the flowchart in Appendix A outlining the high level steps of the AQP, we consider that the revised Figure 1 renders the flowchart in Appendix A redundant and we propose to delete it. This means Appendix B Timelines for Applicant-Specific Solutions and for Competing Applications Group would now be Appendix A.

1450. We do not accept the suggestions in paragraphs 1688 and 1689 of the draft decision that tables like those in Appendix B of the AA3 AQP should be retained in the AA4 AQP. The alternative flowchart replacing Figure 1 provides a sufficiently detailed overview of the transfer and connection application processes and the associated clause references. The tables in Appendix A of the AA3 AQP are generally paraphrased or extracted AQP provisions without providing any explanatory value or any detail not otherwise in the operative provisions.

1451. As we propose to remove the flowchart from Appendix A, as well as the tables in Appendix A, Appendix B Timelines for Applicant-Specific Solutions and for Competing Applications Group is proposed as Appendix A. Consequential amendments are also proposed to clause 1.1. Western Power has also identified additional clause references to be included in Appendix A relating to applicant-specific solutions.

1452. We consider the operative provisions of the AQP, Figure 1 and Appendix A Timelines for Applicant-specific Solutions and for Competing Applications Group contain a sufficient level of detail and information for readers to understand how the AQP operates, in accordance with sections 5.7(b) and 5.7(e) of the Access Code.

1453. We also consider that given the elevated status of the AQP and its capacity to modify contracts (see sections 2.4A(a), 2.5(a), 2.6(a) of the Access Code), care should be taken to exclude non-essential, paraphrased or summarised information and notations as they could cut across the interpretation of core provisions with unknown effects.

18.5 More than one change or modification within 12 months

ERA required amendment 81:

Clause 10.3(c) of the applications and queuing policy must be amended as follows, to require Western Power to accept the change of covered service, where the new covered service is sufficient to meet the actual requirements of the applicant.

"(c) <u>must</u>~~may~~, subject to this clause 10, accept the change of covered service, where ~~Western Power is satisfied, as a reasonable and prudent person, that~~ the new covered service will be sufficient to meet the actual requirements of the applicant, and that it is required by reason of one or more of the following circumstances:"

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

1454. The ERA has proposed the following amendment to clause 10.3(c):

(c) <u>must</u>~~may~~, subject to this clause 10, accept the change of covered service, where ~~Western Power is satisfied, as a reasonable and prudent person, that~~ the new covered service will be sufficient to meet the actual requirements of the applicant, and that it is required by reason of one or more of the following circumstances

1455. Western Power considers the replacement of the word ‘may’ with ‘must’ is acceptable, subject to the following comments:

- the wording ‘Western Power is satisfied, as a *reasonable and prudent person*, that’ should be reinstated
- if Western Power’s discretion is to be limited in any way, paragraphs (c)(i), (iv) and (vii) should be deleted as they are too broad and vague and by their nature require discretionary decisions to determine whether applications to change covered services on such bases are reasonable and justified. Clause (c)(ii) should also be clarified. If the ERA considers Western Power’s discretion under clause 10.3(c) should be removed or limited in any way, then triggers requiring the exercise of discretion and judgment to determine whether they are invoked should be excluded from the provision
- the wording ‘notwithstanding clause 10.3(c)’ should be inserted at the start of paragraph (d) to avoid any doubt that paragraph (d) prevails over clause 10.3(c), otherwise paragraph (d) could be rendered redundant and there may be no means for Western Power to legitimately refuse changes sought in response to seasonal changes.

1456. We consider the above changes are necessary and justified as frequent changes in covered services require the use of Western Power’s resources and result in costs to Western Power which may be included in the reference tariff if the service is provided to the user as a standard metering service. Where this occurs Western Power does not recover all its costs from the user and therefore costs are passed onto other users via network tariffs. Due to the impacts on Western Power and other users of frequent changes in services, we consider any amendments to clause 10.3(c) must ensure Western Power remains able to assess, while balancing all relevant interests, whether any second or subsequent requests to change services within a 12-month period are reasonable and appropriate.

1457. Western Power proposes an amended clause 10.3(a) in the Revised AQP as follows:

If Western Power receives:

(a) more than 1 *application* or notice under clause 10.2; or

(b) more than 1 *application* or notice under clause 10.2,

seeking to change the *covered service,* including to decrease or increase the contracted capacity, with respect to a single *connection point* in any rolling period of 12 months, then in relation to each additional *application* or notice Western Power:

(c) must, subject to this clause 10, accept the change of *covered service*, where Western Power is satisfied, as a *reasonable and prudent person*, that the new *covered service* will be sufficient to meet the actual requirements of the *applicant*, and that it is required by reason of one or more of the following circumstances:

~~(i) a change in the actual *consumption* or *generation* by the *applicant* in respect of that *connection point* over the 12 month period prior to the *applicant* giving notice under clause 10.2(a) (as applicable), as recorded by the *metering equipment*; or~~

(i) a fundamental change in the nature of the business or operation conducted at the connection point; or

(ii) a shutdown of the business or operation conducted at the connection point (including a shutdown for maintenance purposes) for longer than 1 continuous month; or

~~a rapid increase or decline in the business at the connection point; or~~

(iii) a decrease in the number of capacity credits (as defined in the Market Rules) allocated to any generating plant at the connection point under the Market Rules; or

(iv) as part of a *relocation*,~~;~~ ~~or~~

~~(v) some other special circumstance,~~

and

(d) notwithstanding clause 10.3(c), is entitled to refuse the change in *covered service* where Western Power is satisfied, as a reasonable and prudent person, that the change is sought by reason of the seasonal nature of the business or operation at the *connection point*.

19. Contributions Policy

1458. The ERA requires eight amendments to the Contributions Policy. This section details Western Power's response to each required amendment to the Contributions Policy in turn. Additional improvements have also been added as 'other minor amendments'.

19.1 Provision of security for new revenue

ERA required amendment 82:

The drafting of clause 4.3 of the contributions policy must be amended in accordance with paragraph 1739 of this draft decision to add further clarity and to make the terminology consistent throughout the policy.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1459. Western Power accepts this amendment and has made the necessary changes in the Contributions Policy attached to the revised proposed access arrangement. Western Power notes that it has also made a minor numbering change in respect to the two definitions relevant to clause 4.3.

1460. The revised clause 4.3 of the Contributions Policy (Appendix C.1 to the access arrangement) reads as follows:

4.3 Applicant Must Provide Security for New Revenue

~~For the purposes of this clause 4.3:~~

~~"**estimated new revenue**" means the amount calculated under clause 5.2(d).~~

~~"**allocated forecast costs**" means the amount of the forecast costs allocated to the applicant under clause 5.4.~~

(a) Western Power may require an *applicant* to provide a security~~a bank guarantee~~ under this clause if Western Power determines there to be a risk of not receiving the *estimated new revenue*.

(b) Western Power may require the *applicant* to ~~procure~~provide security in the form of an unconditional, irrevocable bank guarantee, or equivalent financial instrument, in terms acceptable to Western Power guaranteeing *new revenue* in the amount of:

(i) the *estimated new revenue* (where the *estimated new revenue* is less than the *allocated forecast costs*); or

(ii) the *allocated forecast costs* (where the *estimated new revenue* is more than the *allocated forecast costs*).

(c) Where Western Power requires a security under clause 4.3(b), the applicant must provide it before the commencement of the *works* the subject of the *connection application*.

(d) Where an *applicant* has provided security under clause 4.3(c), then 24 months after the commencement of the associated *exit service*, *entry service*, or *bidirectional service* Western Power will reconsider the risk of not receiving the *estimated new revenue* (based on the then expected use of those services) and if that risk:

(i) no longer remains, Western Power will return the security,

(ii) remains, but has abated, Western Power may reduce the amount of the security by requiring a new ~~bank guarantee~~security for the reduced amount, or

(iii) has crystallised (such that some or all of the *estimated new revenue* will not be recovered by Western Power), Western Power will re-determine the *contribution* under this *contributions policy* and recover from the *applicant* any difference from the amount of any original *contribution* and, after that recovery, return the security.

(e) In applying this clause Western Power will act as a *reasonable and prudent person*

(f) For the purposes of this clause 4.3:

"**estimated new revenue**" means the amount calculated under clause 5.2(d).

"**allocated forecast costs**" means the amount of the forecast costs allocated to the applicant under clause 5.4.

19.2 Revenue offset for residential customers

ERA required amendment 83:

Clause 5.2(d) of the contributions policy must be amended in accordance with paragraph 1747 of this draft decision to expressly state that the revenue offset in clause 5.2 is applicable to residential customers. A cross-referencing error in clause 5.2 must be also be corrected – the reference to *"clause 7.41.1(a)"* in clause 5.2(c) should be a reference to *"clause 7.4(a)"*.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1461. Western Power accepts the amendments to correct the clause-referencing error in clause 5.2 and to expressly identify that the revenue offset in clause 5.2 is applicable to residential customers in accordance with paragraph 1747 of the ERA's draft decision which states:

> *The ERA considers Western Power's proposal to expand the revenue offset to residential customers is consistent with section 5.12(a) of the Access Code as it achieves the objective of striking the balance between the interests of contributing users, other users and consumers (which includes residential customers). While the ERA agrees that clause 5.2 of the contributions policy is not required to be amended in order to give effect to this "change", the ERA is of the view that the revenue offset in clause 5.2 should always have been applicable to residential customers.*

1462. Western Power has made the necessary changes in the Contributions Policy attached to the revised proposed access arrangement to reflect these amendments. The revised clause 5.2(d) reads as follows:

5.2 Calculation of Contribution

The *contribution* payable in respect of any works to which this *policy* applies is calculated by:

…

(c) adding any applicable amount calculated under clause 7.4~~1.1~~(a), and

(d) deducting the amount likely to be recovered in the form of *new revenue* gained from providing *covered services* to the *applicant*, or, if the *applicant* is a *customer* (including residential customers), to the *customer's retailer*, as calculated over the *reasonable time*, at the *contributions rate of return*; and

…

19.3 Other minor amendments to the Contributions Policy

1463. In required amendment 84, the ERA requires the Introduction section of the Distribution Low Voltage Connection Headworks Scheme (DLVCHS) to be renamed. We have accepted these amendments in respect to the DLVCHS. For consistency, we propose making the same modifications to the Contributions Policy which are set out as follows:

- Delete "**1. Introduction**" and replace with:

  1. Defined Terms and Interpretation

- Delete "**1.1 Definitions**" and replace with:

  1.1 Defined Terms

- Retain the numbering and terminology in section 1.2 as follows:

  1.2 Interpretation

1464. Western Power has made the above changes in the Contributions Policy (Appendix C.1) to the access arrangement.

19.4 Distribution low voltage connection headworks scheme

19.4.1 Section 1 – definitions

ERA required amendment 84:

The distribution low voltage connection scheme methodology must be amended to rename the following sections:

- 1 ~~Introduction~~ Defined Terms and Interpretation
- 1.1 ~~Definitions~~ Defined Terms

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1465. In its draft decision, the ERA states:

> *Due to the insertion of a new interpretation section (see paragraph 1775 below) the ERA requires section 1 to be renamed "defined terms and interpretation" and insertion of a new section 1.1 ("defined terms"). The ERA considers that this will make the DVLHS methodology consistent with the format of the contributions policy.*[315]

1466. In addition, footnote 434 in the ERA's draft decision, identifies that 'Interpretation' should become section 1.2.

1467. Western Power has made the necessary changes in the DLVCHS (Appendix C.2 to the revised proposed access arrangement) to implement the amendments identified in the ERA's draft decision as follows:

- Delete "**1. Definitions**" and replace with:

  1. Defined Terms and Interpretation

- Insert a section 1.1 as:

  1.1 Defined Terms

- 'Interpretation' becomes section 1.2:

  1.2 Interpretation

[315] Paragraph 1764, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

19.4.2 Section 2.3 – overview of the distribution low voltage connection scheme

ERA required amendment 85:

The drafting of section 2.3(a) of the distribution low voltage connection scheme methodology must be amended in accordance with paragraph 1766 to reflect common drafting conventions.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1468. The ERA's draft decision requires section 2.3(a) of the DLVCHS to be amended as follows:

> (a) The distribution low voltage connection scheme and associated prices apply to the provision of distribution low voltage connection scheme works only. The class of applicants must meet the ~~following criterion~~criteria that:
>
> > (i) The proposed or existing connection point for a new or upgraded connection is to the distribution system low voltage network and is within 25 kms of the relevant zone substation

1469. Western Power agrees with this amendment in principle, however, to reflect that there is only one numbered item, Western Power proposes that section 2.3(a) be presented as a single bulleted paragraph (rather than having sub-bullet point), as follows:

> (a) The distribution low voltage connection scheme and associated prices apply to the provision of distribution low voltage connection scheme works only. The class of applicants must have a proposed or existing connection point for a new or upgraded connection to the distribution system low voltage network ~~and~~ which is within 25 kms of the relevant zone substation.

19.4.3 Section 4 – methodology overview

ERA required amendment 86:

The drafting of section 4 of the distribution low voltage connection scheme methodology must be amended in accordance with paragraph 1768 to correct some formatting and typographical errors.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1470. Western Power accepts the formatting and typographical corrections made by the ERA and has made the necessary changes in the DLVCHS (Appendix C.2 to the revised proposed access arrangement).

19.4.4 Section 5.1 – price tranche thresholds

ERA required amendment 87:

Section 5.1 of the distribution low voltage connection scheme methodology must be amended to reinstate the words: "the past 12 month period" (and delete the proposed words "the 12 month period since the most recent review of prices").

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1471. The ERA's principle rationale for the reinstatement of "the past 12 month period" is that it could be interpreted as forward looking and has the effect of altering the original meaning of the clause as detailed in paragraph 1770 of the ERA's draft decision:

> *The proposed changes amend the time period for modelling connections from "the past 12 month period" to "the 12 month period since the most recent review of prices". The ERA considers this change to be ambiguous because "the 12 month period since" could be interpreted as forward looking. The ERA considers that the amendment has the effect of altering the original meaning of the clause. On the basis that Western Power's proposed changes are for the purposes of adding clarity, the ERA requires the current drafting be reinstated, which is considered clearer.*

1472. For reference, the ERA's draft decision requirement for clause **5.1 Price Tranche Thresholds** of the DLVCHS is:

> Western Power has developed standard *distribution low voltage connection scheme* prices based on modelling of *connections* over the past 12 month period ~~the 12 month period since the most recent review of prices~~.

1473. Western Power accepts the rationale for the required amendment, however would like to note that this approach has the potential to increase the volatility of the DLVCHS rate associated with for example, the broadening of data to include residential sites (brownfields).

1474. Customer service is a priority for Western Power with one of our core values being Customer Focus. Rate volatility would have an adverse impact on customers as their projects can typically take from 6 to 12 months from the application date to be delivered.

1475. An alternative option may be to provide some discretion to Western Power to prescribe a longer period over which the data is modelled such as up to 36 months. This will allow Western Power to better manage price volatility and smooth the DLVCHS rates more effectively for applicants.

1476. In addition, having regard to the development of DLVCHS rates being an ongoing process, we propose the following changes to section 5.1:

> Western Power ~~has~~ develop<u>s</u>~~ed~~ ….

1477. We propose the following amendment to clause **5.1** to address the matters identified above:

> Western Power ~~has~~ develop<u>s</u>~~ed~~ standard *distribution low voltage connection scheme* prices based on modelling of connections over <u>at least</u> the past 12 month period.

1478. Western Power has made the above changes in the DLVCHS (Appendix C.2 to the revised proposed access arrangement).

19.4.5 Section 6 – exclusion

ERA required amendment 88:

Section 6 of the distribution low voltage connection scheme methodology must be amended to reinstate the words: "the last twelve months" (and delete the proposed words "the 12 month period since the most recent review of prices").

Western Power's response:

Western Power accepts this amendment in principle, with modifications

1479. Aligned with required amendment 87 and the previously noted paragraph 1770 of the ERA's draft decision, the ERA's principle rationale for the reinstatement of 'the past 12 month period' is that it could be interpreted as forward looking and has the effect of altering the original meaning of the clause.

1480. The ERA's amendment is:

> *The proposed changes amend the time period for determining the exclusion threshold from "the last twelve months" to the "12 month period since the most recent review of prices." For the reasons given at paragraph 1770 above, the ERA considers this change to be ambiguous and should not be made.*[316]

1481. For reference, the ERA's draft decision requirement for clause Section 6 Exclusion is:

6 Exclusion

A *distribution low voltage connection scheme application* is excluded from the provisions of the *distribution low voltage connection scheme* where the *distribution low voltage connection scheme base charge* plus the exclusion threshold is less than the *forecast costs* of *works* as determined under clause 5.4 of the *contributions policy*.

The methodology for determining the exclusion threshold is as follows:

(a) For all works in the last twelve months ~~12 month period since the most recent review of prices~~Western Power will:

(i) determine the amount of the *forecast costs* of the works applied to the *applicants* as per section 5.4 of the *contributions policy*,

(ii) subtract from the amount in section (a) the *distribution low voltage connection scheme base charge*,

(b) The exclusion threshold is equal to two standard deviations of all instances where the value in section (ii) is positive

Western Power will publish the amount of the exclusion threshold as detailed in this document.

316 Paragraph 1773, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, ERA, May 2018.

1482. Similar to Western Power's response to amendment 87, we propose the following modifications to clause 6 of the DLVCHS:

6 Exclusion

A *distribution low voltage connection scheme application* is excluded from the provisions of the *distribution low voltage connection scheme* where the *distribution low voltage connection scheme base charge* plus the exclusion threshold is less than the *forecast costs* of *works* as determined under clause 5.4 of the *contributions policy.*

The methodology for determining the exclusion threshold is as follows:

(a) For all works ~~in the last twelve months~~ over the same period over which connections are modelled under clause 5.1 Western Power will:

   (i) determine the amount of the *forecast costs* of the works applied to the ***applicants*** as per section 5.4 of the *contributions policy*,

   (ii) subtract from the amount in section (a) the *distribution low voltage connection scheme base charge*,

(b) The exclusion threshold is equal to two standard deviations of all instances where the value in section (ii) is positive

1483. Western Power has made the above changes in the DLVCHS (Appendix C.2 to the access arrangement).

1484. In addition, Western Power will publish the amount of the exclusion threshold as detailed in this document.

19.4.6 Interpretation (proposed section 1.1)

ERA required amendment 89:

Section 1.1(b)(ii) of the distribution low voltage connection scheme methodology must be amended to clarify that if a term is defined in the methodology document (at section 1.1) or in the contributions policy then the term will be given that meaning.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1485. Western Power accepts this amendment and has made the necessary changes in the DLVCHS (Appendix C.2 to the access arrangement)

1486. The revised clause 1.2 Interpretation reads as follows:

1.2~~1.1~~ Interpretation

(d) Unless the contrary intention is apparent:

   (i) a rule of interpretation in the Code; and

   (ii) the Interpretation Act 1984,

   apply to the interpretation of this methodology document.

(e) Unless:

(i) the contrary intention is apparent: or

(ii) the term has been redefined ~~above~~in clause 1.1 or in the contributions policy,

a term with a defined meaning in the Code has the same meaning in this methodology document.

19.4.7 Other minor amendments

1487. During the course of reviewing the DLVCHS as part of considering the ERA's required amendments, we have also identified a few further amendments to the DLVCHS which we consider clarify existing positions and are therefore are minor in nature. These further amendments are described below.

1488. Western Power proposes to insert the words 'adjoining or nearby' in clauses 4 (b)(i), 4(b)(ii) and 4(d) of the DLVCHS to clarify that under the DLVCHS, the price methodology applied to lots that are connected to the network through a transformer on an adjoining or nearby lot use the same as the price methodology applied to a lot connected to the network through a transformer on the same lot. This wording clarification reflects existing and ongoing practice.

1489. Western Power has implemented this minor amendment in the DLVCHS (Appendix C.2 to the revised proposed access arrangement) as follows:

4 Methodology Overview

This section provides an overview of the methodology used in determining the *distribution low voltage connection scheme* prices. It is noted that the cost of the provision of electricity capacity at a particular location is a function of:

(a) the incremental capacity requirement sought by an *applicant*; and

(b) whether:

(i) the location of the connection point is on the same, adjoining or nearby land lot as the *relevant distribution* transformer (transformer direct connection); or

(ii) the connection point is supplied from the low voltage street network (street feed connection).

as determined by Western Power having regard to what is the most prudent and efficient network connection design.

On this basis, the approach taken to develop the *distribution low voltage connection scheme* prices is as follows.

(a) Western Power determines the costs of *distribution low voltage connection scheme works* for *connection* of *applicants* that meet the eligibility criterion for the *distribution low voltage connection scheme* over a period of 12 months.

(b) The costs of *distribution low voltage connection scheme works* determined under (a) have been allocated to categories as follows:

(i) whether the incremental capacity requirement at the *connection point* determined under clause 6.3(a) of the *contributions policy* is:

- less than 216 kVA; or
- between 216 kVA and 630 kVA; or
- greater than 630 kVA and

(ii) whether:

(A) *the location of the connection point is on the same, adjoining or nearby land lot as the relevant distribution transformer (transformer direct connection); or*

(B) the *connection point* is supplied from the low voltage street network (street feed connection).

as determined by Western Power having regard to what is the most prudent and efficient network connection design.

(c) From the costs of *distribution low voltage connection scheme work* and the incremental capacity requirement associated with the categories defined in (b) above, the total costs of supply for each tranche can be determined in terms of $ per kVA.

(d) The price structure and prices are then derived to reflect the average costs derived under (a) and (b) above. Prices are expressed in a block structure that provides for a continuous price path. Note that there is a separate price path for a *connection point* on the same, adjoining or nearby land lot as the *relevant distribution transformer* to those with a *connection point* supplied from the low voltage street network.

1490. In line with the amendments to clause 4 above Western Power also proposes to insert the words 'same, adjoining or nearby' in clause 2.3(c) of the DLVCHS to clarify the inclusion of transformers on neighbouring land lots, noting there is no change in current practice.

1491. Further, Western Power proposes to include the words 'distribution low voltage connection scheme' in clause 2.3 to distinguish from the price an applicant pays could include other additional charges such as Appendix 8 of the Access Code asset relocation costs.

2.3 Overview of the Distribution Low Voltage Connection Scheme

(a) The *distribution low voltage connection scheme* and associated prices apply to the provision of *distribution low voltage connection scheme works* only. The class of applicants must have a proposed or existing connection point for a new or upgraded connection to the distribution system low voltage network and within 25 kms of the relevant zone substation.

(b) The prices are in terms of $/kVA.

(c) The distribution low voltage connection scheme price that an applicant pays depends on their incremental capacity requirement and whether the location of the connection point is on the~~a~~ same, adjoining or nearby land lot separate from the relevant distribution transformer.

20. Transfer and Relocation Policy

1492. This section details Western Power's response to the ERA's required amendments to the Transfer and Relocation Policy (TaRP).

20.1 Assignments other than bare transfers (clause 5)

ERA required amendment 90:

Clause 5.3 of the transfer and relocation policy must be amended to remove the redundant words ", if any," as follows. "… Western Power's reasonable opinion may be based on, without limitation, credit reference information available to Western Power and in forming its opinion Western Power will take into account any relevant information~~, if any,~~ provided by the proposed assignee."

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

1493. The ERA has proposed the deletion of the words ", if any," from clause 5.3 of the TaRP. Western Power accepts this amendment and have made the necessary changes in the TaRP (Appendix D to the revised proposed access arrangement).

20.2 Relocations (clause 6)

ERA required amendment 91:

Clause 6.4 of the transfer and relocation policy must be amended in accordance with paragraph 1840 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

1494. The ERA has proposed the following amended wording to clause 6.4 of the Transfer and Relocation Policy.

6.4 Consent

a. A relocation is conditional upon the user obtaining the consent of Western Power. Western Power:

i. must withhold its consent to a relocation where it would impede the ability of Western Power to provide a covered service sought in an access application;

ii. may withhold its consent to a relocation on reasonable commercial or technical grounds; and

iii. may consent to a relocation subject to conditions provided that the conditions are required on reasonable commercial and technical grounds.

b. Without limitation, a condition of consent under clause 6.4a.iii. may include that Western Power must receive at least the same amount of revenue as it would have received before the relocation or more revenue if the tariffs at the destination point are higher.

c. If Western Power withholds its consent to a relocation, or imposes a condition in respect of a relocation, Western Power must provide the user, on the user's written request, with an explanation of the grounds relied upon.

1495. Western Power accepts the Authority's amendments to clause 6.4 in principle with modifications to:

- identify throughout clause 6.4 the terms that are being used as defined terms by *italicising* those terms;
- clarify in clause 6.4.a.i. that Western Power must withhold its consent if the relocation will impede the ability of Western Power to continue to provide an existing covered service of an existing user; and
- clarify in clause 6.4.c. what the explanation by Western Power is to relate to.

1496. We consider the Authority's wording at clause 6.4.a.ii. already provides for Western Power to withhold its consent to a relocation that would impede the ability of Western Power to continue to provide a covered service of an existing user because to do so would be unreasonable on commercial and technical grounds. The modifications proposed by Western Power is to clarify that existing position.

1497. Western Power proposes to modify clause 6.4 as follows:

6.4 Consent

a. A relocation is conditional upon the user obtaining the consent of Western Power. Western Power:

i. must withhold its consent to a relocation where it would impede the ability of Western Power to provide a covered service sought in an access application or continue to provide an existing covered service to an existing user;

ii. may withhold its consent to a relocation on reasonable commercial or technical grounds; and

iii. may consent to a relocation subject to conditions provided that the conditions are required on reasonable commercial and technical grounds.

b. Without limitation, a condition of consent under clause 6.4a.iii. may include that Western Power must receive at least the same amount of revenue as it would have received before the *relocation* or more revenue if the tariffs at the destination point are higher.

c. If Western Power withholds its consent to a *relocation*, or imposes a condition in respect of a *relocation*, Western Power must provide the *user*, on the *user*'s written request, with an explanation of the grounds relied upon by Western Power to withhold its consent or impose conditions.

21. Summary of Western Power's responses to the ERA's required amendments

ERA required amendment 1:

The revisions submission date must be amended to 1 January 2021.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 2:

Western Power must amend its proposed revised access arrangement to:

- remove the correction factor for under or over-recovery of target revenue for prior periods from the price control formula; and
- add a requirement that the forecast customer numbers, energy volumes and any other charging parameters for each reference service must be consistent with the demand forecast approved with the access arrangement decision.

Western Power's response:

Western Power does not accept this amendment and maintains its original position

ERA required amendment 3:

A clause should be added to 5.12 of the proposed revised access arrangement stating that prices for access applications will be consistent with the applications and queuing policy and prices for extended metering services will be consistent with the model service level agreement.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 4:

The proposed revised access arrangement values for TR_t and DR_t must be amended to reflect the ERA's draft decision of target revenue. Western Power should review its smoothing profile to avoid price shocks and ensure the final year reduces the likelihood of price shocks in the next access arrangement period.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 5:

The proposed revised access arrangement must be amended to reflect the forecast operating expenditure set out in Table 31 *[of the draft decision]*.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 6:

The proposed access arrangement revisions must be amended to incorporate the forecast capital expenditure, depreciation and capital asset base values set out in this draft decision.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 7:

Western Power must amend the (nominal after-tax) weighted average cost of capital to 6.00 per cent, based on the parameters set out in Table 75 of this draft decision and reasoning detailed in Appendix 5 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 8:

The values of smoothed target revenue, forecast new facilities investment, forecast non-capital costs and weighted average cost of capital used to calculate working capital must be adjusted to be consistent with this draft decision.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 9:

Forecast taxation costs must be updated to be consistent with the draft decision and must be allocated between services based on the proportion of revenue. The K-factor must not be included in the calculation.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 10:

Western Power must update the Investment Adjustment Mechanism value to reflect the ERA's draft decision on AA3 capital expenditure.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 11:

Western Power must update the Gain Share Mechanism to reflect the ERA's draft decision on wood pole expenditure and unforeseen events and must allocate the value between services based on revenue proportions.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 12:

Western Power must adjust target revenue to remove its proposed unforeseen event adjustment.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 13:

The proposed new time of use reference services must not be mandatory.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 14:

Western Power must unbundle metering services from reference services and specify separate metering services as reference services based on the meter reading services required by users.

Western Power's response:

Western Power does not accept this amendment and proposed a modified position.

ERA required amendment 15:

Western Power must amend Appendix E of the access arrangement in line with Table 117 of the draft decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 16:

Western Power must amend the 2018/19 Price List and Price List Information to be consistent with the target revenue approved by the ERA in this draft decision.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 17:

Western Power must expand Table 16 and Table 18 in Appendix F.4 ("2018/19 Price List Information") to include transmission tariffs.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 18:

Western Power must amend the side constraint formula to remove the correction factor for under or over recovery of target revenue from prior periods.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 19:

Western Power must amend the 2018/19 Price List and Price List Information to include tariffs for each metering service. Evidence must be provided to demonstrate the proposed charges are cost reflective.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 20:

Western Power must demonstrate the proposed new reference tariffs meet the requirements of the Access Code including that they recover the forward looking efficient costs of providing reference services and are set between the incremental and stand-alone cost of service.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 21:

Western Power must provide cost information to support its proposed Excess Network Usage Charges, including the factors applied for different geographical areas.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 22:

Western Power must reinstate the system minutes interrupted performance measures disaggregated for radial and meshed networks as service standard benchmarks.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 23:

For the purpose of monitoring the service provider's actual performance against actual service standard performance and in accordance with sections 11.2 and 11.3 of the Access Code, Western Power must amend section 4.5 of the access arrangement as follows:

4.5.3 Where Western Power has applied a Box-Cox transformation of the daily unplanned SAIDI data set to determine the major event day threshold, Western Power must:

1) Demonstrate that the natural logarithm of the data set of each unplanned SAIDI value is not normally distributed.

2) Provide the calculations that demonstrate the application of the Box-Cox transformation method to the unplanned SAIDI values.

3) Provide the data set resulting from applying the Box-Cox transformation method.

4) Demonstrate that the resulting data set is normally distributed or that the normality of the data set is improved.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 24:

Western Power must set service standard benchmarks at the 97.5^{th} percentile of the single distribution of best fit for all reliability performance measures, except call centre performance and circuit availability for which the service standard benchmark must be set at the 2.5^{th} percentile of the distribution of best fit, to the most recent five-years of performance data.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 25:

Western Power must set service standard benchmarks and targets for a momentary average interruptions frequency index for the fourth access arrangement period.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 26:

Section 7.1.1 of the proposed revised access arrangement must be amended to include a requirement for Western Power to demonstrate that the unrecovered costs are efficient costs and do not exceed the costs which would have been incurred by a service provider efficiently minimising costs.

Western Power's response:

Western Power accepts this amendment as required by the ERA.

ERA required amendment 27:

Section 7.1.4 of the proposed revised access arrangement must be deleted.

Western Power's response:

Western Power accepts this amendment as required by the ERA.

ERA required amendment 28:

Western Power must delete the proposed amendments to section 7.2.1 of the proposed revised access arrangement – the current wording must be retained.

Western Power's response:

Western Power accepts this amendment as required by the ERA.

ERA required amendment 29:

Metering expenditure must be removed from the investment adjustment mechanism.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 30:

Section 7.4.8 of the proposed revised access arrangement must be deleted.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 31:

The formula in section 7.4.7 of the proposed revised access arrangement must be amended so that efficiency savings are retained for four years.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 32:

Section 7.4.3 of the proposed revised access arrangement must be amended to specify that an adjustment, based on the proportion of service standard benchmark failures over the access arrangement period, will be made to the total above-benchmark surplus.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 33:

Western Power must delete the following tables from the proposed revised access arrangement and include a single table with efficiency and innovation benchmarks for the total business consistent with the ERA's determination of efficient operating costs:

Table 32: Efficiency and innovation benchmarks for the transmission system

Table 33: Efficiency and innovation benchmarks for the distribution system

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 34:

Western Power must amend the efficiency and innovation benchmarks to be consistent with the draft decision on operating expenditure.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 35:

Western Power must maintain service standard targets for the 2017/18 financial year at the level applied during the AA3 period.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 36:

Western Power must remove the financial penalties and rewards from the service standard adjustment mechanism.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 37:

Western Power must set service standard targets at the 50th percentile of the single probability distribution of best fit.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 38:

Western Power must delete proposed new sections 7.6.6 to 7.6.10 from the access arrangement.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 39:

Section 8.1.2 of the proposed revised access arrangement must be deleted.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 40:

Section 9.1 of the proposed revised access arrangement, which sets out general provisions for supplementary matters, must be amended in accordance with paragraph 1269 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 41:

Section 9.2.1 of the proposed revised access arrangement, which sets out supplementary matters for line losses, must be amended in accordance with paragraph 1271 of this draft decision.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 42:

Clause 3.1(c) of the electricity transfer access contract must read:

"For each Service at each Connection Point, the User must endeavour, as a Reasonable and Prudent Person, to ensure that the rate at which electricity is transferred into or out of the Network by or on behalf of the User does not exceed the Contracted Capacity for that Service."

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 43:

The electricity transfer access contract must be amended to correct a formatting (numbering) error to show new clauses 3.2(c) and 3.2(d).

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 44:

Proposed new clauses 3.2(c) and 3.2(d) must be deleted from the electricity transfer access contract.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 45:

Clause 3.3 of the electricity transfer access contract should be amended in accordance with paragraph 1337 of this draft decision to ensure that a user will not be in breach of its obligation in the event its breach arises because of Western Power.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 46:

Given the changes to clause 6.2(b) of the electricity transfer access contract, clause 33.4 of contract must be amended in accordance with paragraph 1342 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 47:

Clause 9(i) of the electricity transfer access contract should be amended to capitalise the term “services” as follows.

“ … the aggregate amount of cash deposit held by Western Power (including interest and after deducting any fees, charges and taxes associated with maintaining the interest bearing account) exceeds the Charges for two months’ ~~s~~Services Western Power will, within a reasonable time…”

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 48:

Clause 13(c)(i) of the electricity transfer access contract must be amended to expressly set out the characteristics of generating plant that, if changed, will constitute material modifications for the purpose of that clause.

Proposed clause 13(c)(ii) must be deleted from the electricity transfer access contract unless the modifications that are contemplated by clause 13(c)(ii), which would not fall within clause 13(c)(i), are clearly identified.

Western Power’s response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 49:

Subject to clause 13(c)(ii) remaining in the electricity transfer access contract, the notification period in clause 13(c)(ii) must be amended from 60 to 30 days.

Western Power’s response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 50:

Subject to clause 13(c)(ii) remaining in the electricity transfer access contract, clause 13(c)(ii) must contain an express obligation for Western Power to notify the user within the notice period if it forms the view that the modification will have an adverse impact on safety or security, failing which the modification can proceed.

Western Power’s response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 51:

Clause 19.5 of the electricity transfer access contract must be amended in accordance with paragraph 1383 of this draft decision to amend the drafting of clause 19.5(c) and insert a new clause 19.5(d).

To support new clause 19.5(d) the term “material change” needs to be added to schedule 1 of the electricity transfer access contract in accordance with paragraph 1384 of this draft decision.

Western Power’s response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 52:

Clause 19.8 of the electricity transfer access contract must be amended in accordance with paragraph 1388 of this draft decision to make minor drafting amendments.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 53:

Clause 19.11(a) of the electricity transfer access contract must be amended in accordance with paragraph 1392 of this draft decision.

Western Power’s response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 54:

The following consequential amendments that arise from the deletion of clause 35.1(b)(iv) must be made to the electricity transfer access contract.

- The words "facsimile copy" should be deleted from clause 1.1(d).
- The word "facsimile number" should be deleted from clause 36.
- The words "facsimile number" from Part 1 and Part 2 of the table in schedule 6 should be deleted.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 55:

The term “Claims” in Part 1(a)(i)(A) of schedule 5 of the electricity transfer access contract must be amended to correct the use of the word claims as follows.

“public liability insurance for a limit of not less than $50 million or the maximum liability of the User under clause 19.5 (whichever is greater) in the aggregate of all ~~C~~claims made in an Insured Year; and”

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 56:

Clause 6.2(b) of the electricity transfer access contract must be amended to correct the use of the word *contract* in accordance with paragraph 1430 of this draft decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 57:

Clause 7.1 of the electricity transfer access contract must be amended to correct the use of the words *tariff/s* and *consumption* in accordance with paragraphs 1431 and 1432 of this draft decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 58:

Clause 12.2 of the electricity transfer access contract must be amended to correct the use of the words *user* and *party* in accordance with paragraph 1436 of this draft decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 59:

Clauses 19.1, 19.6 and 35.4(d) of the electricity transfer access contract must be amended to correct the use of the word party (or parties) in accordance with paragraph 1438 of this draft decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 60:

Clause 27.1 of the electricity transfer access contract must be amended to correct the use of the word *default* in accordance with paragraph 1439 of this draft decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 61:

Clause 22.3(a) of the electricity transfer access contract must be amended to read:

"promptly notify the other Party of the occurrence of the Force Majeure Event and in any event within two days of the occurrence of the Force Majeure Event; and".

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 62:

Clause 22 of the applications and queuing policy, covering provisions for dormant applications, must be amended in accordance with paragraph 1507 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 63:

Clause 24.3(c) of the applications and queuing policy, dealing with an applicant's response to a notice of intention to respond to a preliminary access offer, must be amended to replace the word "may" with "will" in accordance with paragraph 1511 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 64:

Clause 24.5 of the applications and queuing policy, dealing with an applicant's response to a preliminary access offer, must be amended in accordance with paragraph 1515 of this Draft Decision to:

- clarify that the 30 business days commence after the receipt of the notice (clause 24(a)(ii)); and
- replace the word "may" with "will" (clause 24.5(a)(ii)(B)).

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 65:

Clause 20.2(a)(i) of the applications and queuing policy must be amended to read:

"Western Power must provide a proposal <u>within a reasonable time</u> to the applicant outlining the scope, timing and good faith estimate …"

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 66:

The proposed amendments to include forecast natural load growth in the definition of spare capacity and clause 24.8(a) of the applications and queuing policy must be deleted.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 67:

Clause 24.1(c) of the applications and queuing policy must be amended as follows to make it consistent with other clauses in the policy:

" … and the applicant will be deemed to have made a request for~~requested~~ a study under clause 20.3(a)."

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 68:

Clauses 18.1 and 19.1 of the applications and queuing policy, setting out provisions for a preliminary assessment and initial response, must be amended in accordance with paragraph 1554 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 69:

Clause 24.3(a) of the applications and queuing policy must be amended in accordance with paragraph 1577 of this Draft Decision to include the words: "and where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract".

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 70:

Clause 24.5(b) of the applications and queuing policy must be amended in accordance with paragraph 1582 of this Draft Decision to include the words: "and where it exceeds any contribution payable under

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 71:

Clause 13.3 of the applications and queuing policy, requiring Western Power to reject an application where the customer is not a contestable customer, must be amended in accordance with paragraph 1603 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 72:

Proposed new clause 12A ("Relationship with transfer and relocation policy") must be deleted from the applications and queuing policy.

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 73:

The definition of "connection application" (at clause 2.1) in the applications and queuing policy must be amended in accordance with paragraph 1631 of this Draft Decision to add the words *"in a way that means they no longer meet the eligibility criteria".*

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 74:

Proposed amendments to clause 6.2(a) of the applications and queuing policy, which allows the disclosure of confidential information to the market operator or where necessary for the performance of Western Power's functions, must be deleted.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 75:

Clause 24.9(d) of the applications and queuing policy must be amended in accordance with paragraph 1644 of this Draft Decision to provide that Western Power must not make known confidential information under the clause if it is possible from the anonymised information to determine the identity of the competing connection applicant.

Western Power's response:

Western Power does not accept this amendment and maintains its original position.

ERA required amendment 76:

Clause 4.8 of the applications and queuing policy, containing provisions for conditions precedent, must be amended in accordance with paragraph 1660 of this Draft Decision to:

- set a fixed upper limit on the period allowed in sub-clause (a); and
- better link sub-clauses (a) and (b).

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 77:

The proposed amendments to support "time of use" tariffs and advanced metering (change identification numbers 27 to 31) must not be made to the applications and queuing policy.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 78:

The definition of "Customer Transfer Code" in clause 2.1 of the applications and queuing policy must be amended to refer to the Electricity Industry Customer Transfer Code 2016 (and not the Electricity Industry Customer Transfer Code 2004).

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 79:

Clauses 3.15(a); 4.8(b)(i); 24.3(b); 24.5(a) and 24.6 of the applications and queuing policy should be amended to improve drafting clarity in accordance with paragraph 1679 of this Draft Decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 80:

The applications and queuing policy must retain Figure 1 ("Access, Connection and Transfer Applications Policy – Process Overview").

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 81:

Clause 10.3(c) of the applications and queuing policy must be amended as follows, to require Western Power to accept the change of covered service, where the new covered service is sufficient to meet the actual requirements of the applicant.

"(c) must~~may~~, subject to this clause 10, accept the change of covered service, where ~~Western Power is satisfied, as a reasonable and prudent person, that~~ the new covered service will be sufficient to meet the actual requirements of the applicant, and that it is required by reason of one or more of the following circumstances:"

Western Power's response:

Western Power does not accept this amendment and proposes a modified position.

ERA required amendment 82:

The drafting of clause 4.3 of the contributions policy must be amended in accordance with paragraph 1739 of this draft decision to add further clarity and to make the terminology consistent throughout the policy.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 83:

Clause 5.2(d) of the contributions policy must be amended in accordance with paragraph 1747 of this draft decision to expressly state that the revenue offset in clause 5.2 is applicable to residential customers. A cross-referencing error in clause 5.2 must be also be corrected – the reference to *"clause 7.41.1(a)"* in clause 5.2(c) should be a reference to *"clause 7.4(a)"*.

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 84:

The distribution low voltage connection scheme methodology must be amended to rename the following sections:

- 1 ~~Introduction~~ Defined Terms and Interpretation
- 1.1 ~~Definitions~~ Defined Terms

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 85:

The drafting of section 2.3(a) of the distribution low voltage connection scheme methodology must be amended in accordance with paragraph 1766 to reflect common drafting conventions.

Western Power’s response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 86:

The drafting of section 4 of the distribution low voltage connection scheme methodology must be amended in accordance with paragraph 1768 to correct some formatting and typographical errors.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 87:

Section 5.1 of the distribution low voltage connection scheme methodology must be amended to reinstate the words: "the past 12 month period" (and delete the proposed words “the 12 month period since the most recent review of prices”).

Western Power’s response:

Western Power accepts this amendment in principle, with modifications.

ERA required amendment 88:

Section 6 of the distribution low voltage connection scheme methodology must be amended to reinstate the words: "the last twelve months" (and delete the proposed words “the 12 month period since the most recent review of prices”).

Western Power’s response:

Western Power accepts this amendment in principle, with modifications

ERA required amendment 89:

Section 1.1(b)(ii) of the distribution low voltage connection scheme methodology must be amended to clarify that if a term is defined in the methodology document (at section 1.1) or in the contributions policy then the term will be given that meaning.

Western Power’s response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 90:

Clause 5.3 of the transfer and relocation policy must be amended to remove the redundant words “, if any,” as follows. “… Western Power’s reasonable opinion may be based on, without limitation, credit reference information available to Western Power and in forming its opinion Western Power will take into account any relevant information~~, if any,~~ provided by the proposed assignee.”

Western Power's response:

Western Power accepts this amendment as proposed by the ERA.

ERA required amendment 91:

Clause 6.4 of the transfer and relocation policy must be amended in accordance with paragraph 1840 of this draft decision.

Western Power's response:

Western Power accepts this amendment in principle, with modifications.