Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network 2017/18 – 2021/22

Submitted by Western Power

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FINAL DECISION

1. The Economic Regulation Authority's (ERA) final decision is to not approve Western Power's proposed revisions to the access arrangement for the Western Power Network. The ERA requires 66 amendments to be made before it will approve the revised access arrangement. Detailed reasons for the required amendments are outlined in this document.[1]

2. Under section 4.19 of the *Electricity Networks Access Code 2004* (Access Code), Western Power may submit an amended access arrangement proposal to the ERA within 20 business days of this final decision, that is, by 19 October 2018.

3. The ERA will consider Western Power's amended proposal (if received) before making a further final decision to approve or not approve the revised access arrangement. Where the ERA's further final decision is to not approve Western Power's proposed revisions, the ERA must draft and approve its own revised access arrangement within 20 business days of publishing its further final decision.

Background

4. On 2 October 2017, Western Power submitted proposed revisions to the access arrangement for the Western Power Network. The submission was made in accordance with the requirements of section 4.79 of Access Code and is for the fourth access arrangement period (AA4) from 1 July 2017 to 30 June 2022.

5. The ERA is required to consider the proposed revisions and make a decision to either approve or not approve the revisions. The ERA must determine whether Western Power's proposed revisions:

   - Meet the Access Code objective of promoting economically efficient investment in, and operation and use of, electricity networks and services of networks in Western Australia, in order to promote competition in markets upstream and downstream of the networks.
   - Comply with the specific requirements of the Access Code.

6. On 6 October 2017, the ERA invited submissions from interested parties on Western Power's proposed revisions. The closing date for submissions was 20 November 2017. To assist interested parties the ERA published an issues paper on 31 October 2017 and held a public information forum on 2 November 2017.

7. Following requests from interested parties the ERA extended the deadline for submissions to 11 December 2017. The extension gave parties an opportunity to consider additional supporting information that was provided by Western Power (and published by the ERA), including Western Power's revenue model, regulatory financial statements and a productivity report.

8. Submissions were received from 32 interested parties and published on the ERA's website. Under section 4.12 of the Access Code, the ERA must consider any

[1] The required amendments are listed in Appendix 1 and are also included in the reasons to the decision at the point where each relevant element of the proposed revision is considered.

submissions received on Western Power's proposed revisions and must make a draft decision, either:

- To approve the proposed revisions to the access arrangement.
- or
- To not approve the proposed revisions, in which case the ERA must in its reasons provide details of the amendments required before the ERA will approve it.

9. The ERA published its draft decision on 2 May 2018 to not approve Western Power's proposed revisions to the access arrangement because the revisions did not satisfy the requirements of the Access Code. In its reasons for the draft decision, the ERA detailed 91 amendments that were required before it would approve the revised access arrangement.

10. At the time of issuing its draft decision, the ERA invited submissions from interested parties on the decision, with a requirement for submissions to be received by 30 May 2018. In response to requests from interested parties, the ERA extended the deadline for submissions to 14 June 2018. Submissions were received from 17 interested parties and published on the ERA's website.[2]

11. Western Power's submission on the draft decision included a revised access arrangement proposal as permitted under section 4.16 of the Access Code. Western Power also submitted revised access arrangement information.

12. On 17 August 2018, the ERA published a notice advising of new information that could affect Western Power's rate of return. Interested parties were invited to make submissions by 29 August 2018. Submissions were received from three parties and published on the ERA's website.

13. Section 4.17 of the Access Code requires the ERA to consider any submissions made on the draft decision (including Western Power's revised access arrangement proposal) and make a final decision that either:

    - Approves Western Power's revised access arrangement proposal.
    - or
    - Does not approve Western Power's revised proposal, in which case the ERA must provide details of the amendments required before the ERA will approve the revisions.

14. Western Power's current access arrangement applies until a new revised access arrangement is approved by the ERA.

[2] A list of interested parties who made a submission is included in Appendix 3.

REASONS

REGULATORY FRAMEWORK

Requirements for an access arrangement

17. Western Power's transmission and distribution network is a covered network under the *Electricity Networks Access Code 2004* (Access Code) and is required to have an approved access arrangement. The access arrangement sets out the terms and conditions, including prices, for third parties seeking access to the network.

18. Chapter 5 of the Access Code specifies the required content of an access arrangement. Western Power's access arrangement must include:

- A revisions submission date for submitting revisions to the access arrangement.
- The method used to determine the total revenue Western Power can collect from customers.
- One or more reference services.
- The pricing method for each reference service.
- Service standard benchmarks for each reference service.
- Any adjustments that will be made to target revenue at the next access arrangement review.
- Any trigger events that would require a review to commence earlier than planned.
- A standard access contract for each reference service.
- An applications and queuing policy.
- A contributions policy.
- A transfer and relocation policy.

19. Western Power is required to submit proposed revisions to the access arrangement and access arrangement information to the ERA by the revisions submission date specified in the access arrangement. The revisions submission date approved in the third access arrangement (AA3) decision was 31 March 2016. This was later amended to 31 December 2016, the latest date permitted under the Access Code. The Access Code was subsequently amended to extend the deadline to 2 October 2017.

20. As set out in chapter 4 of the Access Code, the ERA is required to consider Western Power's proposed revisions to the access arrangement and make a decision to either approve or not approve the proposed revisions. The ERA must determine whether the proposed revisions:

- Meet the Access Code objective of promoting economically efficient investment in, and operation and use of, electricity networks and services of networks in Western Australia, in order to promote competition in markets upstream and downstream of the networks.

- Comply with the requirements set out in chapter 5 of the Access Code.

21. If the ERA considers the Access Code objective and chapter 5 requirements are satisfied it must approve the proposed revisions. The ERA may not reject proposed revisions to the 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 of chapter 5. If the ERA does not approve the proposed revisions it must provide details of the amendments required.

22. The process the ERA must follow for the review of an access arrangement is set out in chapter 4 of the Access Code and includes:

    - making and publishing a draft decision for public consultation
    - making and publishing a final decision
    - if required, making and publishing a further final decision.

23. Where the ERA's draft decision is to "not approve", Western Power may choose to submit a *revised* access arrangement proposal as part of its submission in response to the draft decision. The ERA must make and publish a final decision, either "approving" or "not approving" the revised proposal (or the initial proposal if no revised proposal is received).

24. Where the ERA's final decision is to "not approve", Western Power may choose to submit an *amended* access arrangement proposal. The ERA must make and publish a further final decision, either "approving" or "not approving" the amended proposal.

    - If the ERA's further final decision is to "approve", Western Power's amended proposal becomes the revised access arrangement and takes effect from a date specified by the ERA, which must be at least 20 days after its decision is published.
    - If the ERA's further final decision is to "not approve", the ERA must draft, approve, publish and advertise its own access arrangement.

25. Where Western Power does not submit an amended access arrangement proposal in response to the ERA's final decision to not approve its (initial or revised) proposal, the ERA must publish a further final decision to "not approve" and then draft, approve, publish and advertise its own access arrangement.

26. Specific stages of the review and approval process must be completed in the timeframes prescribed by the Access Code. Deadlines must initially be set on the prescribed timeframes. While there are provisions for extensions of time, the ERA can only use these provisions if it determines:

    - A longer time period of time is essential for due consideration of all the matters under consideration or satisfactory performance of the relevant obligation.
    - The ERA or Western Power (as applicable) has taken all reasonable steps to fully utilise the times and processes provided for in the initial deadline.

27. Before extending any deadline the ERA must publish a notice in accordance with section 4.65(a) of the Access Code.

28. If the ERA exercises its powers to obtain information and documents under section 51 of the *Economic Regulation Authority Act 2003*, time ceases to run in respect of the relevant deadline until the information is received.

29. The ERA published its draft decision to not approve Western Power's proposed revisions to the access arrangement for the fourth access arrangement period (AA4), on 2 May 2018. Public consultation on the draft decision closed on 14 June 2018.

30. Western Power has submitted a revised access arrangement proposal in response to the ERA's draft decision to not approve its (initial) proposal.

31. The ERA has considered Western Power's revised proposal and all public submissions received on the draft decision in making this final decision. The reasons for this final decision are set out in the following chapters:

- Introduction to the access arrangement
- Revenue requirement
- Form of price control
- Target revenue
- Reference and non-reference services
- Pricing methods, price list and price list information
- Service standard benchmarks
- Adjustments to target revenue at next review
- Trigger events
- Supplementary matters
- Standard access contract
- Applications and queuing policy
- Contributions policy
- Transfer and relocation policy

INTRODUCTION TO THE ACCESS ARRANGEMENT

Access Code requirements

32. Sections 5.29 and 5.31 of the *Electricity Networks Access Code 2004* (Access Code) require an access arrangement to specify:

- A *revisions submission date* that is at least six months before the target revisions commencement date.
- A *target revisions commencement date* that must be five years after the start of the access arrangement period, unless a different date is proposed by the service provider and the different date is consistent with the Access Code objective.

Current access arrangement

33. The current access arrangement initially required Western Power to submit proposed revisions for the fourth access arrangement period (AA4) by 1 March 2016, with AA4 targeted to commence on 1 July 2017.

34. On 6 March 2014, the Minister for Energy launched a review of the electricity market and announced preferred options for development in March 2015. These options included transferring regulation of the Western Power Network from the Western Australian regime to the *National Electricity Law* and *Rules* regime, and also applying the relevant rules to regulate Western Power's metering services

35. In considering the proposed review of the electricity market, Western Power applied to the ERA to defer its revisions submission date. In June 2015, the ERA approved a deferral of the revisions submission date from 1 March 2016 to 31 December 2016.

36. A package of legislative bills to transfer the regulation of Western Power's Network to the national framework was introduced to State Parliament in June 2016. It was intended that the bills would be passed by November 2016, allowing Western Power to commence the review process under the national regulatory framework in December 2016, and for the Australian Energy Regulator's determination to apply from 1 July 2018. However, it became clear the bills would not be passed in time. Consequently, Western Power continues to be subject to the state-based regulatory regime. To provide Western Power with sufficient time to prepare its access arrangement submission, the Minister amended the Access Code to extend Western Power's submission deadline to 2 October 2017, which is three months after AA4 was initially targeted to commence (which was 1 July 2017).

Western Power's initial proposal

37. Western Power's initial proposal included changes to specify the revisions commencement date for AA4, and the revisions submission date and target revisions commencement date for the next access arrangement period:

- The commencement date for AA4 was specified as 1 July 2018, or a later date in accordance with section 4.26 of the Access Code.
- The proposed revisions submission date was specified as 1 March 2021.

- The target revisions commencement date was specified as 1 July 2022.

Submissions on Western Power's initial proposal

38. Submissions from Alinta Energy, CdL Advisory, Community Electricity and ERM Power included comments on the target revisions commencement date and revisions submission date.

39. Alinta, CdL Advisory and ERM Power all referred to current uncertainties and the likelihood of further reforms. They considered the next review should commence earlier and/or the period required for the review would need to be longer.

40. Alinta referred particularly to the State Government's proposal to introduce a constrained access model:[3]

> At this stage there is significant uncertainty as to what this means in practice – particularly with regards to current access rights and what a future connection contract may look like. As such, Alinta considers that it would be prudent to allow a longer than usual period to conduct the AA5 review processes and suggests at least 18 months should be allowed. This additional time will be required in order to allow current users, prospective access seekers, Western Power, and the ERA sufficient time to understand the implications appropriately.

41. ERM Power expressed similar views:[4]

> … given that there may be the possibility of a new regulatory environment, it might be appropriate for the first submissions to be made earlier. How early will depend on how prepared will the ERA be in making a determination in that changed environment. Without an understanding of the undertaking, it is difficult to comment on a timeframe other than a possible commencement before the end of 2020, but certainly no shorter than at least eighteen months. This timeframe is required to allow the market sufficient time to digest the implications of a potential new regulatory environment, the assessment criteria and process.

42. CdL Advisory considered the dates proposed were inappropriate given the "pace of technological disruption" and the "current National Electricity Market crisis and its potential flow on effects to Western Australia's electricity market and regulatory reform environment."[5]

43. Community Electricity also referred to the rapid changes in the energy sector and considers that including more "annual true-ups and resets" in the access arrangement would enable:[6]

> … an incremental approach to tariff reform and provide opportunity to contain and adapt to unforeseen and unknowable consequences.
>
> Annual review would also remove the bureaucratic burden of urgently assembling an Access Arrangement that honours the ritual of the Access Code rather than its spirit. We support Western Power's proposal to the effect that, (our words) government policy is a wildcard that must be implemented and could reasonably be expected to conflict

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[3] Alinta Energy, Alinta Energy Submission, 11 December 2017, section 13.

[4] ERM Power, Issues Paper on Proposed Revisions to Western Power Network Access Arrangement, 11 December 2017, p. 2.

[5] CdL Advisory, Proposed Revisions to the Western Power Network Access Arrangement, 4 December 2017.

[6] Community Electricity, Response to ERA Public Consultation, 10 December 2017, p. 10.

with the Access Arrangement. Clearly the government should not permit delay of its policies while we await termination of a 5-year access arrangement.

Draft decision

44. The Access Code requires the target revisions commencement date to be five years after the start of the access arrangement period, unless a different date is proposed by Western Power and the different date is consistent with the Access Code objective:

- The *access arrangement period* is the period between the revisions commencement date and the next revisions commencement date.
- The *revisions commencement date* is the date on which revisions to an access arrangement that have been approved by the ERA commence.
- Western Power’s proposed target revision commencement date (of 1 July 2022) is five years after AA4 was originally intended to commence (which was 1 July 2017).

45. Western Power’s initial proposed revisions included a target revenue proposal for a five year period commencing 1 July 2017. The delays in transferring the regulation of Western Power’s Network to the national framework means that the AA4 revisions will take effect after 1 July 2017. This requires adjustments to the approved target revenue to take account of any differences between the revenue approved by the ERA in its AA4 decision, and the revenue actually earned by Western Power between 1 July 2017 and the date the AA4 revisions come into effect. On this basis, Western Power’s proposed target revisions date was equivalent to a five year period.

46. The AA4 period should not be reduced to accommodate changes to the regulatory framework. If a significant change does occur, there are provisions in the Access Code that allow Western Power to apply for, or the ERA to require, a mid-period review of the access arrangement[7] (which could be part of, not the entire, access arrangement). A mid-period review is preferable to shortening the access arrangement period because a shorter period could reduce the incentive for Western Power to out-perform its cost forecasts and achieve efficiencies that will ultimately be passed on to network users. A shorter regulatory period would also increase regulatory costs.

47. The Access Code specifies that the revisions submission date must be at least six months prior to the target revision date. The minimum timeframes prescribed in the Access Code result in an access arrangement review taking at least nine months.[8] When extensions of time are applied, as permitted under the Access Code, the length of time increases to 18 months. Where additional information is required from Western Power, the review process may take even longer, as was the case for Western Power’s first access arrangement (AA1).

48. Previous reviews have required the full time permitted under the Access Code with extensions. The average time was 18 months:

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[7] See section 4.38 of the Access Code for provisions enabling the ERA to require an amendment; section 4.41 requiring revisions if the Access Code is amended; and section 4.41A allowing Western Power to propose a mid-period variation.

[8] Including the one month prescribed minimum period for the revised access arrangement to come into effect following the ERA’s decision.

- AA1 was submitted on 24 August 2005 with the further final decision published on 26 April 2007 and the revisions commencing on 1 July 2007 (22 months in total).
- The second access arrangement (AA2) was submitted on 1 October 2008 with the further final decision published on 19 January 2010 and the revisions commencing on 1 March 2010 (17 months in total).
- The third access arrangement (AA3) was submitted on 30 September 2011 with the further final decision published on 29 November 2012 and the revisions commencing on 1 February 2013 (16 months in total).

49. The Australian Energy Regulator's review process commences approximately twenty four months prior to the target revision date.

50. Western Power's proposed revisions submission date (of 1 March 2021) met the requirements of the Access Code. However, based on the ERA's and Australian Energy Regulator's experience of previous access arrangement reviews, the ERA considered a period of 18 months was 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.

51. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision Required Amendment 1

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

Western Power's revised proposal

52. In the revised proposal, Western Power has not accepted the draft decision required amendment 1 set out in paragraph 51 above. Western Power has amended the proposed submission date from 1 March 2021 to 26 February 2021, recognising that 1 March 2021 is a public holiday in Western Australia. Western Power submits:

> 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.
>
> 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.
>
> 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.
>
> 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.

53. Western Power has amended the assumed start date for AA4 to 1 November 2018, which it based on the ERA issuing a further final decision in September 2018 and providing for the one month minimum prescribed period for the revised access arrangement to come into effect following the ERA's decision.

Submissions on draft decision

54. Synergy submits that it will require four to six months from the further final decision to implement revised tariffs in its billing system[9]:

> In addition to pricing changes, AA4 contains a range of matters that will require additional operational and system implementation by users[10]. For example, to cater for new reference services, metering services and AMI. Therefore, Synergy requires the ERA, in specifying a start date for AA4, to give consideration to the time required to implement the changes in AA4. Synergy considers it will need between 4-6 months from the date of the final or further final decision to make the necessary changes to implement AA4.

Considerations of the ERA

55. Western Power has proposed a commencement date for AA4 of 1 November 2018 which it based on the ERA issuing a further final decision in September 2018 and allowing for the minimum period permitted under the Access Code between the date of the decision and the revised access arrangement coming into effect.

56. Synergy has advised it requires at least four to six months from the further final decision to implement revised tariffs.

57. Allowing for the maximum permissible time of 90 business days between the final decision and commencement of the revised access arrangement means a realistic commencement date for AA4 is February 2019. For the purposes of this final decision, the ERA has assumed new tariffs will commence on 1 February 2019. The commencement date will be confirmed in the further final decision.

58. In the draft decision, the ERA required Western Power to bring forward the proposed submission date for the next access arrangement review to provide eighteen months for the next review, rather than the sixteen months proposed by Western Power. Eighteen months would allow for the full time extensions permitted under the Code to be used[11] and still complete the review prior to the planned commencement date.

59. Western Power has not accepted this amendment and argues that 16 months should be sufficient for the fifth access arrangement period (AA5) review given the "relative maturity of the review process". Western Power considers the revisions submission date should be as close as possible to the target revisions commencement date to give greater certainty that the assumptions made in the initial submission will remain valid during the access arrangement. Western Power considers it is in the interest

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9 Synergy, *Economic Regulation Authority draft decision on proposed revisions to the access arrangement for the Western Power network*, June 2018, p. 63.

10 This includes system changes to cater for build pack changes that may result from WP's proposed MSLA.

11 Although the time required would be longer if the ERA does not approve the access arrangement in its further final decision. If that were to occur, the process could take an additional two months.

of customers for access arrangement reviews to be conducted in as short a time frame as possible.

60. The ERA agrees reviews should be conducted in a timely manner but must also allow sufficient time for consideration of all issues and consultation with stakeholders. As raised in stakeholder submissions, there is likely to be significant legislative and regulatory changes affecting Western Power leading up to the next review. The currency of the demand and financial assumptions can be ensured by allowing for these values to be updated where necessary during the process, as has occurred during previous reviews.

61. It would be preferable for the submission date to enable the full extension times to be used without resulting in the access arrangement commencing later than the target commencement date. However, as Western Power’s proposed date meets the minimum requirement of the Access Code, the ERA must accept the proposal.

TOTAL REVENUE REQUIREMENT

Overview

62. This chapter assesses Western Power's proposed form of the price control and the determination of target revenue in the following order.

- Form of price control
- Forecast target revenue:
  - Forecasts of demand for services
  - Forecast operating expenditure
  - Actual capital expenditure for the third access arrangement period (AA3) and the value of the regulated capital base at the commencement of the fourth access arrangement period (AA4)
  - Forecast capital expenditure and the forecast value of the regulated capital base over the AA4 period
  - Return on the regulated capital base
  - Allowance for working capital
  - Cost of taxation liabilities
  - Cost of raising additional equity
  - Adjustments to target revenue for AA4 to reflect certain cost and revenue outcomes during AA3
  - Tariff equalisation contributions

63. In considering Western Power's proposed target revenue, the Economic Regulation Authority (ERA) has undertaken the following assessments of actual and forecast costs for AA3 and AA4.

- An assessment of whether the forecast operating costs for AA4 meet the requirement of section 6.40 of the *Electricity Networks Access Code 2004* (Access Code) of including only those costs that would be incurred by a service provider efficiently minimising costs.
- An assessment of whether capital expenditure incurred in AA3 may be added to the capital base under section 6.51A of the Access Code, including an assessment of whether, and to what extent, the capital expenditure satisfies the new facilities investment test under section 6.52 of the Access Code.
- An assessment of whether forecast capital expenditure for AA4 may be taken into account in determining target revenue (by inclusion in the forecast regulated capital base), including an assessment of whether, and to what extent, the capital expenditure can reasonably be expected to satisfy the new facilities investment test under section 6.52 of the Access Code.

64. For the purpose of approving proposed revisions to an access arrangement, and pursuant to sections 6.41, 6.51 and 6.51A of the Access Code, the ERA has discretion as to whether to recognise costs in the total costs and target revenue that underlie the price control. This includes forecast operating costs, actual capital expenditure during AA3 and forecast capital expenditure for AA4. Before recognising these costs in total costs and target revenue, the ERA must be satisfied

that the costs meet the tests of section 6.41, 6.51 and 6.51A of the Access Code. It is the responsibility of Western Power to demonstrate to the ERA that the costs satisfy these tests.

65. In making an assessment of Western Power's costs the ERA has considered:

- Western Power's performance during the AA3 period, in particular:
  - significant under expenditure (when comparing actual costs with the forecast costs taken into account by the ERA in setting target revenue for AA3); and
  - good performance against service standards;
- the proposed reductions in Western Power's forecast expenditure for AA4 (when comparing the forecast expenditure with actual AA3 expenditure); and
- the efficiency of operating expenditure, including a comparison of Western Power's costs with other network service providers.

66. The ERA obtained independent advice from GHD Advisory (GHD) and Geoff Brown and Associates (GBA) on relevant matters including:

- a review of Western Power's governance arrangements for controlling work programs and costs;
- a review of actual capital expenditure during AA3 (including a sample of capital projects and programs) claimed by Western Power to meet the new facilities investment test under section 6.52 of the Access Code;
- a review of Western Power's forecast operating expenditure for AA4, including benchmarking against other network service providers; and
- a review of forecast capital expenditure for AA4 (including a sample of capital projects and programs) claimed by Western Power to meet the new facilities investment test under section 6.52 of the Access Code.

67. The ERA has assessed the actual and forecast costs against the relevant requirements of the Access Code and, where it has determined that the requirements of the Access Code are not met, exercised discretion to amend the amounts of costs to be taken into account in determination of target revenue.

Form of price control

Access Code requirements

68. The Access Code requires an access arrangement to include a "price control", which means the provisions in an access arrangement under section 5.1(d) and chapter 6 (of the Access Code) which determine target revenue. A note to this definition indicates that a price control can consist of direct or indirect limits, and is a limit on the *level* of tariffs through the control of overall revenue. This note also distinguishes between price control and pricing methods, with the latter dealing with the *structure* of tariffs.

69. The specific requirements and objectives for price control and determining target revenue are set out in sections 6.1 to 6.5 to the Access Code (and are reproduced below).

- Sections 6.1 and 6.2 state requirements for the form of price control, while sections 6.4 and 6.5 set out the objectives that must be met by the price control.
- Section 6.3 constrains the choice of price control for the first access arrangement period, which is not relevant to the assessment of Western Power's proposed revisions (and is not reproduced below).
- Section 6.4 sets out objectives for price control in relation to the setting of an amount of target revenue for the access arrangement period.
- Section 6.5 clarifies that the forward-looking and efficient costs of providing covered services is a target amount (and not a ceiling or a floor amount).

Form of Price control

6.1 Subject to section 6.3, an access arrangement may contain any form of price control provided it meets the objectives set out in section 6.4 and otherwise complies with this Chapter 6.

6.2 Without limiting the forms of price control that may be adopted, price control may set target revenue:

(a) by reference to the service provider's approved total costs; or

(b) by setting tariffs with reference to:

(i) tariffs in previous access arrangement periods; and

(ii) changes to costs and productivity growth in the electricity industry;

or

(c) using a combination of the methods described in sections 6.2(a) and 6.2(b).

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;[12]

plus

[12] Section 6.5A to 6.5E – Recovery of deferred revenue.

(iii) an amount (if any) determined under section 6.6;[13]

plus

(iv) an amount (if any) determined under section 6.9;[14]

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;[15]

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.

Current access arrangement

70. The current access arrangement applies a "revenue cap" form of price control. Under this form, reference tariffs are set on the basis of a target revenue comprising an amount of required revenue for a given year, plus corrections for under or over-recovery of target revenue in prior years.

71. The formula for calculating target revenue each year when setting annual tariffs is set out in sections 5.6 and 5.7 of the current access arrangement. The formula includes a separate factor for any costs incurred by the distribution system resulting from any Tariff Equalisation Contribution (**TEC**) that Western Power is required to pay in accordance with section 6.37A of the Access Code.

72. The revenue cap applies to all network access services that Western Power provides to transmit and distribute electricity, whether they are a reference or non-reference service, including:

- connection services;
- exit services;
- entry services;
- bi-directional services;
- metering services provided ancillary to the above services (that are defined as standard metering services in the model service level agreement); and
- streetlight provision and maintenance.

73. Separate revenue caps have been determined for services provided by the transmission and distribution networks.

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13 Section 6.6 – Target revenue may be adjusted for unforeseen events.

14 Section 6.9 – Target revenue may be adjusted for technical rule changes.

15 Section 6.37A – Tariff equalisation contributions may be added to target revenue.

74. The revenue cap for each of the transmission and distribution networks was determined using a building block approach incorporating the following costs:

- operating costs (non-capital costs);
- depreciation;
- return on the regulated capital base;
- return on working capital;
- taxation; and
- adjustments from the previous access arrangement period.

75. The regulated capital base is derived as follows:

    opening capital base + forecast capital expenditure – depreciation – redundant assets = closing capital base

76. Services that are ancillary to the transmission and distribution of electricity, such as high load escorts, are not included in the revenue cap. Consequently, forecast operating costs attributed to such services are not included in target revenue.

77. Revenue for services defined as standard metering services are recovered in the revenue cap as reference services and all other services provided under the model service level agreement are *non-revenue cap* (non-reference) services.[16]

78. The current access arrangement specifies that charges for non-revenue cap services are negotiated in good faith, are consistent with the Access Code objective and are reasonable.

Western Power's initial proposal

79. Western Power 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; and
- set charges for non-revenue cap services on the same basis as for AA3.

Submissions on Western Power's initial proposal

80. Submissions from the Australian Energy Council, Community Electricity, Emergent Energy, Perth Energy and Synergy included comments relevant to the price control. Details of these submissions are included below.

[16] "Non-revenue cap services" is a defined term in the access arrangement and means *"non-reference services provided by Western Power by means of the Western Power Network other than non-reference services that are provided as revenue cap services"*.

Draft decision

Revenue cap services

81. In assessing Western Power's proposed revisions, and in particular the proposed form of price control, the ERA must assess whether the proposal complies with the Access Code (section 6.2, the objectives of section 6.4 and otherwise chapter 6) and have regard to the Access Code objective.

82. A revenue cap is explicitly contemplated in the note to section 6.2(a) of the Access Code as one of several forms of price control that may be adopted.

83. Submissions from Synergy and Emergent Energy highlighted the effect of demand risk on a revenue cap form of price control.

84. Synergy stated it did not oppose a revenue cap form of price control for the transmission and distribution services, noting it is consistent with the approach adopted by the Australian Energy Regulator (AER). However, Synergy noted this form of price control means Western Power's customers face significant demand risk which places a strong onus on Western Power to:

> … apply best practice in forecasting demand for the purposes of its AA4 proposal, to substantiate its demand forecasts (including the methodology and assumptions used) and to provide its customers and stakeholders with reasonable opportunity to review and comment on its methodology, assumptions and forecasts.

85. Emergent Energy also raised concerns about the effect of changes in demand on revenue and pricing:

> As both peak demand and overall consumption falls (due to the introduction of disruptive competition), Western Power must not simply raise prices to fully recover their proposed revenue cap. The Authority should consider backward solving for a revenue cap, based on an appropriate tariff escalation regime which takes changes to the sector, and the risks associated with it, into consideration. If the Authority-derived revenue cap is less than that required for cost recovery, then some asset write down is necessary.[14]

86. Community Electricity and Perth Energy commented on the alternative options now available to customers which they may choose in preference to energy supplied by the network.

87. Community Electricity submitted:

> ….for the first time, customers may choose between 'grid' and 'non-grid' solutions. Previously, customers have had no choice but to accept Western Power's policy and fund its right to raise revenue to provide a return on investment and cover operational costs.
>
> Customer choice is the driver of the 'networks death spiral' whereby fixed network revenues are proportioned to decreasing consumption.
>
> …
>
> It is imperative that Western Power aligns its charges with the decisions and behaviours it wishes to promote, and adapts to the different revenues that these prices will cause.[15]

88. Perth Energy noted that:

> … downstream of the network Western Power is no longer a monopoly. Western Power now competes with behind the meter energy solutions, as a way to energise

> customer's facilities. …. The increasing costs faced by customers downstream of the network, coupled with the declining costs of behind the meter energy solutions such as solar and batteries will displace reliance on the electricity network.

89. As discussed further in the section on demand forecasting, Western Power has forecast a decline in energy consumption during the AA4 period. This is the first access arrangement for which Western Power has forecast reductions in demand.

90. As identified in Synergy's submission, Western Power's current price control puts all demand risk on users. Under Western Power's current price control, any changes in energy consumption or customer numbers compared with the access arrangement demand forecast affect charges to users during the access arrangement period as any under- (or over-) recovery of target revenue is passed through to users in the following year's charges. This can result in charges to users being significantly different from those projected at the time of an access arrangement decision.

91. 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).[17] However, Western Power's proposed 2013/14 Price List would have resulted in average charges increasing by 17.5 per cent more than CPI. Two and a half percentage points of this was due to an increase in the TEC. The remainder was due to differences in revenue and demand forecasts compared with the demand forecasts underpinning the AA3 final decision.

92. An amendment was made to Western Power's access arrangement which reduced the effect of this large increase.[18] However, due to energy volumes being lower than forecast in Western Power's AA3 submission, and the TEC being higher than forecast, the combined transmission and distribution average charges during AA3 increased by more than CPI as shown in Table 1 below.

Table 1 AA3 annual increase in average charges including forecast CPI (nominal)[19]

	Total	Transmission	Distribution	Forecast CPI
2012/13	3.7%	-8.7%	7.2%	2.25%
2013/14	4.0%	-12.0%	5.3%	2.0%
2014/15	4.8%	-0.8%	6.9%	2.75%
2015/16	5.1%	-10.2%	10.3%	2.5%
2016/17	1.7%	-9.4%	4.8%	2.5%

93. As shown in Table 1 (above), the increase in average charges was greater than the forecast rate of inflation. The final year was lower than CPI only because Western Power did not take up its maximum allowable revenue. Western Power chose to

[17] See final decision notice published on 5 September 2012. https://www.erawa.com.au/cproot/10738/2/20120905%20-%20D94273%20-%20Western%20Power%20final%20decision%20AA3%20Notice.pdf

[18] See Mid-Period Variation – Revision to Revenue Caps to reflect revised recovery period of Deferred Revenue published on 4 June 2013 http://www.erawa.com.au/cproot/11386/2/20130604%20D106966%20-%20Decision%20to%20amend%20price%20control%20in%20Western%20Power%20s%20access%20arrangement%20AA3.pdf

[19] Extracted from annual price lists approved and published on the ERA website.

defer $29.7 million[20] in the 2016/17 Price List. Without this deferral, average charges would have increased by 4.2 per cent. Under its pricing formula, Western Power will be able to recover the $29.7 million in future years.

94. In the draft decision, the ERA took the view that Western Power's current price control has not met the objectives of 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 met the objective of section 6.4(c) to avoid price shocks.

95. Other matters which may be affected by the current price control, and that are relevant to considering the price control against the Code Objective are:

- Users have reported difficulties and delays when seeking to connect to the network.[21]
- 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.
- Under the current price control, users face distorted incentives to manage demand. Any steps they take to reduce demand will be reflected in future in higher charges. This may lead to users seeking non-network alternatives.

96. If Western Power was exposed to demand risk, which could be increases or reductions in demand compared to forecast, it would face stronger incentives to 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.

97. In the draft decision, the ERA required amendments to Western Power's proposed price control in order to:

- enable users to predict the likely annual changes in target revenue during the access arrangement period (as required under section 6.4(b) of the Access Code); and
- avoid price shocks, i.e. sudden material tariff adjustments between succeeding years (as required under section 6.4(c) of the Access Code).

98. The ERA considered this would be achieved by ensuring demand risk is faced by Western Power rather than users, and that this could be best be-achieved 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.

99. The ERA required the following amendment to Western Power's proposal.

Draft Decision Required Amendment 2

Western Power must amend its proposed access arrangement to:

[20] Western Power 2016/17 Price List Information Table 7.

[21] See submissions from Emergent Energy and Change Energy.

- 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 revised proposal

100. In its revised proposal, Western Power has not accepted draft decision required amendment two and has maintained its original position of continuing the revenue cap form of price control rather than the price control required by the ERA, which it considers in practical effect is a price cap form of price control.[22]

101. In its revised proposal, Western Power discusses different types of price control. Western Power considers that under a revenue cap it is "afforded limited opportunity to out-perform its revenue requirement and increase its profitability". In contrast it considers a price cap:[23]

> … 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.

102. Western Power notes there are subtle variations of these two forms of price control for regulated monopoly businesses but that generally most forms of price control will either control revenue or control prices.[24]

> 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.
>
> 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.
>
> 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.

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[22] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 16-26.

[23] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 17.

[24] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 17.

103. Western Power describes the ERA's required amendment as requiring Western Power to adopt a price cap form of price control. It considers:[25]

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

104. Western Power then goes on to some specific concerns.

105. Western Power considers the ERA has not demonstrated that Western Power's proposal does not satisfy the Access Code objective.[26]

> 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.

106. Western Power refers to the ERA's draft decision paragraph 86, "based on past experience, the ERA considers Western Power's current price control is not compliant with section 6.4(b) as it has not enabled users to predict the likely annual changes in target revenue and has not been compliant with the requirements of section 6.4(c) to avoid price shocks." Western Power goes on to say:[27]

> 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

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[25] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 18.

[26] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 20.

[27] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 20.

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.

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.

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.

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.

107. Western Power considers the form of price control during the AA3 period satisfied the price control objectives and did not result in price shocks.

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).

…

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. …

We acknowledge the ERA's concerns over the initial 2013/14 Price List. 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.

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.

108. Western Power considers it already takes measures to avoid price shocks under the current form of price control.

… 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.

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.

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.

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.

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.

109. Western Power considers the form of price control does not prohibit development of efficient tariffs or customer connections.

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.

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.

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

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.

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.

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.

110. Western Power submits it is not immune to demand risk.

> 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.
>
> 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.
>
> 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.
>
> 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.
>
> 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.

111. Western Power considers the form of price control should not be considered in isolation.

> 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.
>
> 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.
>
> 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.

112. Western Power considers 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.

> 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.
>
> 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.
>
> 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.[28] Among its many conclusions about the application of price caps, the AER found that:
>
> - There was no evidence of efficient pricing as a result of a price cap
> - The theoretical advantages have not eventuated in practice
> - Placing volume and revenue recovery risk on to the DNSP has resulted in DNSPs over-recovering against the revenue allowance in nearly all cases.

113. Western Power considers the ERA has not shown how its required amendment meets the requirements of sections 6.4(a), 6.4(b) and 6.4(c) of the Access Code:

> 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).

114. Western Power also raises concerns that the ERA's required amendment to the price control would increase the risk of under/over recovery of the TEC from variable charge components and that this risk would be borne by Western Power.

> 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.
>
> 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 and that developing a fixed charge based on an equitable allocation between retailers may provide a more predictable and transparent charge for users.
>
> 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.
>
> However, as noted in correspondence to the ERA following the October 2017 AA4 submission, 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.

[28] AER Framework and Approach NSW Distributors March 2013.

Submissions on draft decision

115. Submissions from the Australian Energy Council, Public Utilities Office, Energy Network Association and Synergy included matters relevant to the price control.

116. The Australian Energy Council supported the change to the price control and considered it to be:[29]

> … an appropriate mechanism to manage demand risk opposed to the network operator simply increasing its risk premium in the weighted average cost of capital calculation and hence increasing its target revenue.

117. The Public Utilities Office submitted that any decision on the level of demand-side risk to be shared between network customers and Western Power is a matter for the ERA but it raised concerns about the ability for Western Power to recover the Tariff Equalisation Contribution.[30]

> The Public Utilities Office is of the view that there is a risk that Western Power will not be able to recover the Tariff Equalisation Contribution (TEC) as a result of the ERA proposing to remove the over and under recovery correction factor.
>
> While any decision on the level of demand-side risk to be shared between network customers and Western Power is a matter for the ERA, this should not impact on the ability for Western Power to meet its regulatory obligations in recovering the TEC from its distribution reference tariffs.
>
> The TEC makes up a large component of Western Power's fixed costs… the amount of the TEC also varies substantially from year to year.
>
> The ERA's draft AA4 decision to remove the correction factor for under or over-recovery of target revenue for prior periods has the potential to exacerbate the risk to Western Power of not recovering the TEC from its network customers. This could be of particular concern where tariffs are based on the demand forecasts approved with the access arrangement decision and the subsequent actual demand is lower than these forecasts.
>
> The Public Utilities Office considers that the recovery of TEC through a fixed charge would be problematic as the amount to be recovered varies from year to year. As noted above, while retailers are able to choose how the TEC is recovered from customers, where it is just passed through as part of a fixed component, it has the potential to distort tariffs and provide inappropriate pricing signals.
>
> The Public Utilities Office suggests that the ERA and Western Power explore alternate options for ensuring recovery of the TEC that would be compliant with the requirements of the Access Code. One option would be to have a dual revenue cap and price cap approach to recover allowable revenue. The revenue cap component could be set equivalent to the forecast TEC and the price cap component could incorporate the remaining revenue.

118. The Energy Networks Association's submission on the draft decision raised several concerns about changing the price control.[31]

> The practical effect of this decision is a price cap form of control. This represents a departure from the approach that was historically applied to Western Power's reference services. Energy Networks Australia also notes that the revenue cap is the most common form of regulation for standard control services and prescribed

[29] Australian Energy Council p. 8.

[30] Public Utilities Office,

[31] Energy Networks Association, 14 June 2018, pp.1-2.

transmission services in the National Electricity Market. That is, the ERA proposes a shift from a more nationally consistent approach to a less consistent approach.

Energy Networks Australia notes that this change is proposed against the backdrop of reductions in demand, as well as an increased quantity forecasting risk that accompanies the growing penetration of distributed energy resources and technological change.

In these circumstances, we consider that the benefits to consumers of mitigating forecasting risk that are achieved by using the revenue cap form of control outweigh the disadvantages. This is because under the price cap approach, if forecast quantities are lower or higher than is believed to be achievable, this may create an incentive to spend less than efficient levels of capital (and operating) expenditure, incurring lower future service outcomes to consumers, or higher than efficient investment later.[32]

The ERA notes that its proposed approach will provide greater price stability and certainty for users. This is true in relation to price changes within the access arrangement period. However, should actual demand differ significantly from the forecast within an access arrangement period, prices will adjust in the first year of the next access arrangement period to take account of updated quantity forecasts. Therefore, consumers remain exposed to the demand risk in the long run and may face significant intra period volatility.

119. Synergy's submission on the draft decision was supportive of the change.[33]

On balance, Synergy considers the ERA's draft decision with respect to price control represents a fresh, positive approach to a range of challenges facing WP and its users, within the confines of the Access Code.

In Synergy's view the ERA's required amendment is economically sound, particularly as it removes the demand risk from users. In effect, the approach turns the current revenue cap mechanism into a form of price cap by requiring the price for services to be calculated on the recovery of efficient costs for a fixed demand forecast per period. Further, depending on how the approach is actually implemented, Synergy considers it would comply with the Access Code's price control requirements.

For users, the ERA's approach has the advantage of enabling them to forecast their own costs with greater confidence. For WP, the approach will result in:

- WP recovering less than the efficient costs in respect of a service if forecast load exceeds actual load in respect of a year; and
- WP recovering more than the efficient costs in respect of a service if actual load year exceeds forecast load in respect of a year.

This means that over or under recovery of costs is to some extent inevitable because demand forecasts for a period, no matter how robust at the time they are made, inevitably differ from actual demand for that period. The extent to which this gives rise to a consistent over or under recovery of WP's costs will be influenced by:

- the robustness of the demand forecasts proposed by WP and adopted or amended by the ERA and contained in an Access Arrangement (thereby incentivising WP to have a robust accurate forecast process); and
- the triggers available in the Access Code to "re-calculate" demand forecasts in respect of a period when it becomes clear they are likely to be inaccurate to some pre-determined extent.

Therefore, Synergy commends the ERA on its approach which should allow users to forecast their own costs with greater confidence than is currently the case.

[32] Commerce Commission is New Zealand, Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower, December 2016, p. 19.

[33] Synergy submission on draft decision, June 2018, p. 40.

Given the importance of forecasts and the triggers for revisions during an Access Arrangement Period, including any threshold for triggers, Synergy expects it, and other users, to be granted an opportunity at the relevant time to review and comment on the detail of any mechanisms that may be proposed by WP or the ERA to implement the ERA's approach. However, in any event, Synergy considers the proposed approach should not result in any adjustment to WP's market risk premium or debt risk premium relative to the position adopted by the ERA in its draft decision.

It is important to maintain the delineation of WP's economic (or 'systematic') risk from the risks that result from business operations ('business' or 'unsystematic' risk). In Synergy's view, forecasting energy demand is unsystematic risk. The reasons for this are:

- Exposure to the risks of energy demand forecasting are a normal part of business operations for a range of energy market participants, including retailers, generators, market operators and energy solutions providers, who factor these risks into their business decisions as for any other risk factor.
- Clause 4 of the SETAC requires users, including retailers, to provide energy demand forecast information to WP in relation to the connection points on their access contract. WP therefore has access to detailed and disaggregated forecast information.
- The Access Code provides trigger mechanisms for WP to mitigate demand forecast risk under sections 4.38, 4.41A and 4.41B, by providing WP with the ability to re-set its forecasts and prices. These mechanisms are not available to other market participants or users who also rely on energy demand forecasts in operating their businesses.

Therefore, in Synergy's opinion the demand forecast risk WP is exposed to is reasonable, and can be managed by sound business practices and, if required, by relying on the mechanisms provided under the Access Code.

ERA considerations

120. In its draft decision the ERA determined that the current price control does not meet the requirements of section 6.4(b) and 6.4(c) of the Access Code. That is, the current price control does not:

- Enable users to predict the likely annual changes in target revenue during the access arrangement (section 6.4(b)).
- Avoid price shocks, i.e. sudden material tariff adjustments between succeeding years (section 6.4(c)).

121. The reason the current price control does not meet these requirements is because it includes an adjustment mechanism so that any under or over-recovery of revenue can be added to or deducted from future years' revenue to be collected from customers. Effectively this means any demand risk (which could be negative or positive) is passed on to customers and Western Power is guaranteed a fixed level of revenue during the access arrangement period.

122. As a consequence, the target revenue to be collected from customers each year during the access arrangement cannot be predicted with any certainty and, depending on how different actual demand is compared with the access arrangement forecast, could result in price shocks to customers (that is sudden material tariff adjustments between succeeding years).

123. Removing the adjustment mechanism from the price control formula and requiring tariffs in each year's price list to be based on demand forecasts consistent with those used in the access arrangement will:

- Enable users to predict the likely annual changes in target revenue during the access arrangement, as they will be in line with the amounts forecast in the access arrangement decision (subject to any changes in the TEC).
- Avoid price shocks, as tariff changes will be in line with the changes forecast in the access arrangement decision (subject to CPI adjustments).

124. Therefore the ERA's draft decision required Western Power to make the following amendments to the price control so that it would be compliant with the requirements of section 6.4(b) and 6.4(c) of the Access Code:

- Remove the correction factor for under or over-recovery of target revenue for prior periods from the price control formula.
- Base the forecast revenue recovery from Western Power's proposed tariffs in each year's Price List on customer numbers and volumes consistent with the demand forecast approved with the AA4 decision.

125. The ERA also observed other matters that may have been affected by the current price control:

- Users reported difficulties and delays when seeking to connect to the network.
- Little change has been made to cost allocations or tariff structures since the current regulatory framework commenced. Most users continue to be charged based on energy volumes.
- Under the current price control, users face distorted incentives to manage demand. Any steps they take to reduce demand will be reflected in future in higher charges which may lead to users seeking non-network alternatives.

126. Ultimately, the ERA did not base its decision to require amendments to the price control on these factors but noted that if Western Power was exposed to demand risk, which could be increases or reductions in demand compared to forecast, it would be more likely to 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. All of these outcomes further the Code Objective.

127. Under the current propose/respond framework of the Access Code there is no provision for the ERA to initiate change in advance of an access arrangement review. This is different from the national electricity regulatory regime that requires the regulator, the AER, to develop the regulatory framework for an access arrangement - including the form of price control – in advance of the service provider submitting its proposal.

128. As described in Western Power's response to the draft decision, the AER currently applies a revenue cap price control to the networks it regulates. Prior to 2013, it typically applied a price cap approach.

129. There are differences between the regulatory framework for the national electricity rules and the Access Code. The national framework does not include specific objectives for predictability of target revenue or avoidance of price shock. The AER also has a greater role in determining tariff structures. In deciding on the price control mechanism the AER must have regard to:

- The need for efficient tariff structures.

- The possible effects of the price control on administrative costs of the AER, network providers and users.
- Regulatory arrangements already in place.
- Desirability for consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction).
- Any other relevant factor.

130. When determining Western Power's price control, the factors the ERA must consider are set out in the Access Code.

131. Western Power has been under a form of revenue cap price control since the first access arrangement. For AA1, an overall revenue cap was applied with no restrictions on specific tariffs.

132. For AA2, the ERA approved a revenue cap but set a fixed side constraint such that tariffs could not be increased above a certain level:

- Transmission – CPI + 13 per cent.
- Distribution – CPI + 18 per cent.

133. The fixed constraints were set in recognition that customers were already facing large price increases and should not be exposed to further increases.

134. For AA3, the ERA approved a revenue cap with an adjustable side constraint (that is, it enabled revenue overs and unders to be included in each tariff). At the time of the AA3 final decision, based on Western Power's demand forecasts, the approved target revenue would have resulted in tariffs increasing in line with CPI, rather than the large increases above CPI approved for AA2. Hence, the ERA approved Western Power recovering any over or under revenue recovery during the access arrangement period.

135. In its initial proposal for AA4, Western Power proposed retaining its current form of price control. The ERA's issues paper published on 31 October 2017 included information on the current price control. The issues paper referred to Western Power's statement in its access arrangement proposal:

> Under the proposed access arrangement, Western Power has the ability to recover less than the revenue cap amounts determined under the formulae … Western Power will be mindful of any material increases in revenue that may occur due to the operation of the formulae and may intentionally under-recover the revenue cap to reduce price shocks that may occur. The revenue correction mechanism can be used to ensure all revenue is recovered.

136. The issues paper provided background on the divergence of actual charges during AA3 compared with those forecast at the time of the AA3 decision and invited submissions on the proposed price control and side constraint formula, in particular any views on how variations in demand during the access arrangement period should be managed to avoid price shocks to customers.

137. Submissions were received from the Australian Energy Council, Community Electricity, Emergent Energy, Perth Energy and Synergy. Western Power did not make a submission.

138. As described in the issues paper and the draft decision, the experience during AA3 demonstrated how unpredictable changes in target revenue can be during an access

arrangement period and the resultant effect on tariffs under the current price control. For AA3 it was possible to partially mitigate this by re-opening the AA3 decision on the recovery period for deferred revenue.

139. The AA3 decision approved a shortening of the period for recovery of deferred revenue (changed from over the life of the assets of 40+ years down to 10 years). The decision was based on the shorter life being manageable without increasing prices, rather than 10 years being “better”. Consequently, shortly after the AA3 decision when Western Power submitted its first price list for the period it became apparent that, rather than prices increasing in line with CPI the proposed increase was 17.5 per cent more than CPI. The ERA considered the proposed increase was of sufficient magnitude for a review under section 4.38 of the Code. The recovery period was changed back to the life of the assets mitigating some of the price increase, but growth in AA3 tariffs was still a couple of percentage points higher than CPI.

140. Price shock could also have arisen in AA2 but did not as the side constraint included a limit on price increases. The AA3 target revenue included a $75 million under-recovery adjustment from AA2.

141. The required amendments to the AA4 price control are similar to the price control approved for AA2. However, the AA2 price control would have required any revenue over-recovery to be adjusted against future charges. The required amendment for AA4 will enable Western Power to keep any revenue arising from increases in demand above its initial forecasts.

142. The ERA’s required amendment could also be viewed as a formalisation of Western Power’s proposed “self-moderating” outlined in its initial proposal as noted in paragraph 135 above.

143. The ERA recognises it would be unreasonable to amend the price control retrospectively, particularly as the AA3 access arrangement included a target commencement date of 1 July 2017 for AA4 which has already passed.

144. The revised price control will come into effect with the first price list approved as part of the AA4 access arrangement. Regardless of the change to the price control, when setting the target revenue, an adjustment is required for the fact that new prices won’t come into effect until part way through the period. The revised price control will only apply from that point forward so there is no retrospectivity. The shorter period until the end of the access arrangement reduces the potential for divergence between forecast and actual revenue as a result of the changed price control.

145. Western Power and the ENA have raised concerns that other aspects of the access arrangement need to be amended if the price control is changed. The ERA considers Western Power should have submitted its best estimates of demand and efficient expenditure regardless of the basis of price control.

146. The ERA also does not agree the range of services, investment profile, and debt/credit rating would change as a result of the amendments to the price control. In particular, the WACC would not be different. The ERA notes that energy networks on both price caps and revenue caps have had similar credit ratings. When the AER

moved from price caps to revenue caps, there was no specific adjustment to the rate of return.[34]

147. The ERA considers the other incentive mechanisms and incentives for efficiencies will continue to operate effectively with the amendments to the price control.

148. The ERA acknowledges the current form of price control does not prohibit the development of efficient tariffs or customer connections. However, the required amendments will improve the incentives for the development of efficient tariffs and customer connections. If Western Power is successful in the customer developments it mentions, it will benefit from the additional revenue.

149. For the reasons set out above, Western Power's current price control is not compliant with sections 6.4(b) and 6.4(c) of the Access Code, that is, it does not enable a user to predict the likely annual changes in target revenue, nor does it avoid price shocks. Under section 4.28(a)(ii) of the Access Code, if the ERA considers that the Code objective or a requirement set out in chapter 5 of the Access Code is not satisfied, it must not approve the proposed access arrangement. In the case of the price control, the requirements of chapter 6 of the Access Code are also relevant.[35]

150. The ERA's required amendments will ensure the price control is compliant with sections 6.4(b) and 6.4(c).

151. The ERA's decision recognises that the revenue adjustment factor in the current price control will lead to changes in target revenue that cannot be predicted and, depending on the level of difference from forecast, can result in price shock.

152. The ERA has also considered the effect of the required amendments on the price control's compliance with section 6.4(a) of the Access Code and the Access Code objective.

- The required amendment will not affect the price control's current compliance with 6.4(a) as Western Power will still have the opportunity to earn revenue to meet its forward looking and efficient costs. As stated in section 6.5 of the Access Code, 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.
- The required amendment is consistent with the Access Code objective and the ERA considers it will better promote economically efficient investment in and operation and use of the network. The required amendments will result in Western Power facing stronger incentives to 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.

[34] Australian Energy Regulator APA Victorian Transmission System final decision attachment 3, Nov 2017, pp. 3-285 to 3-286.

[35] Section 5.1(d) states "include price control under Chapter 6".

Recovery of the Tariff Equalisation Contribution

153. Western Power and the Public Utilities Office have raised concerns that the required amendments to the price control will affect the ability of Western Power to recover the costs of the Tariff Equalisation Contribution (TEC).[36]

154. Under the ERA's required amendments to the price control, the TEC will continue to be included as a separate factor in the price control formula. Each year the target revenue that Western Power can collect through its tariffs will be updated to reflect the gazetted TEC.

155. Under the current price control, variability in customer bills from the TEC arises due to under/over recovery adjustments from previous years and also variations in the annual TEC that is gazetted. The annual TEC can vary quite significantly. For example, the TEC for 2017/18 was $167 million, it has been gazetted to increase to $198 million for 2018/19 and is forecast to reduce to $162 million in 2019/20.

156. As discussed later in Pricing Methods, Price List and Price List Information, under or over recovery of the TEC could be reduced if the costs were passed through as a fixed, rather than variable, charge.

157. Regardless of whether Western Power is able to adjust tariffs for under/over recovery of the TEC from prior periods, there will continue to be variability in future tariffs, depending on the level of TEC gazetted.

158. For example, based on information included in Western Power's proposed 2018/19 Price List Information, the change in the gazetted TEC between 2017/18 and 2018/19 changes average residential customer bills by about $15, which is less than 1 per cent. A five per cent under or over recovery of the 2018/19 TEC as a result of demand being different would change residential customer bills by about $5, which is less than 0.3 per cent.

159. The ERA acknowledges the TEC is a charge that cannot be influenced by Western Power and implements a government policy of uniform tariffs. Consequently, it is reasonable to enable Western Power to collect the TEC charges in full from distribution customers. This can be achieved by including an under/over recovery adjustment in the price control specifically for the TEC element of tariffs.

[36] The TEC is a levy on users of the distribution network that is set by the State Government and imposed to fund subsidy payments to Horizon Power.

Required Amendment 1

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.

Include a correction factor for under or over-recovery of the TEC for prior periods.

Non-revenue cap services

160. In its initial proposal, Western Power stated that the ERA was not required to approve tariffs or charges for non-revenue cap services. Western Power noted the forecast costs for providing these services were not included in the building blocks for target revenue used to calculate the annual revenue caps for revenue cap services.

161. The term "non-revenue cap services" was introduced and approved at the last access arrangement review. It is a defined term in the current access arrangement.

> "***non-revenue cap services***" means *non-reference services* provided by Western Power by means of the *Western Power Network* other than *non-reference services* that are provided as *revenue cap services*.
>
> "***revenue cap services***" means the following covered services provided by Western Power by means of the *Western Power Network*:
>
> a) connection service;
>
> b) exit service;
>
> c) entry service;
>
> d) bi-directional service ..
>
> e) the metering services provided ancillary to the services in paragraphs (a) to (d) that are defined as standard metering services in the model service level agreement …
>
> f) streetlight maintenance.

162. Submissions on Western Power's initial proposal from Synergy, AGL Energy and the Australian Energy Council all commented on Western Power's non-revenue cap services and suggested there was a need for "controls" to ensure efficient tariffs/charges.

163. Western Power's *2016/17 Cost and Revenue Allocation Method* states that its non-revenue cap services include non-reference services such as:

- access applications;
- metering extended services;
- transmission line relocations; and

- other services (e.g. high load escorts and temporary supplies and disconnections).

164. The cost of transmission line relocations and other services will depend on the circumstances of the work required. For these services, the current requirements for non-revenue cap services (to be negotiated in good faith, consistent with the Access Code objective and reasonable) were considered by the ERA in the draft decision sufficient to ensure the charges were consistent with the requirements of the Access Code. The ERA further indicated its intention to update its access arrangement information guidelines to require Western Power to provide a breakdown of non-revenue cap services by category (i.e. access applications, metering, transmission line relocations and other) in its regulatory accounts for both revenue and operating expenditure. Such a requirement will provide further information to confirm that the charges are in line with the costs incurred for the relevant service.

165. Charges for access applications are covered under the applications and queuing policy, while charges for metering extended services are covered under the model service level agreement. While these documents provided adequate oversight for these particular charges, a clause should be added to the access arrangement to explicitly state this.

166. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 3**
>
> A clause should be added to 5.12 of the proposed 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 revised proposal

167. In its revised proposal, Western Power has accepted draft decision required amendment three and has made the necessary changes to clause 5.12.

Submissions on draft decision

168. Synergy raises concerns about Western Power's interpretation of pricing in its model service level agreement:

> In Synergy's experience, WP has adopted an interpretation of the MSLA in which prices for extended metering services contained in the MSLA operate as "fixed prices". This position, which is not necessarily inconsistent with the ERA's remarks with respect to non-revenue cap price control measures, is nevertheless inconsistent with the clear requirements of clause 6.6(1) of the Electricity Industry (Metering) Code 2012 (Metering Code). Clause 6.6(1)(c) of the Metering Code requires the MSLA specify the "maximum charges the network operator may impose for each metering service that" the network operator must provide and may provide.
>
> Clause 6.6(1)(e) of the Metering Code requires the MSLA must provide the charges that may be imposed under a service level agreement may not exceed the costs that would be incurred by a network operator acting in good faith and in accordance with good electricity industry practice, seeking to achieve the lowest sustainable costs of providing the relevant metering service.
>
> The MSLA is therefore required to deal with charges by imposing a "price cap" and a "pricing principle" on WP's pricing conduct. Synergy considers that, were WP to apply

> the requirements of the Metering Code to its pricing conduct in respect of extended metering services, the charges for those services would typically fall below the "price cap".
>
> In Synergy's view any amendments approved by the ERA consistent with Required Amendment 3 must reflect this dual characteristic of the Metering Code's requirements and its application to extended metering services. This is particularly the case given the MSLA is presently under review and its ultimate approved form remains undetermined.

Considerations of the ERA

169. The ERA is satisfied that Western Power has complied with draft decision required amendment three.

170. However, in light of Synergy's submission, which highlights a relevant pricing requirement set out in the *Electricity Industry (Metering) Code 2012*, it would add clarity to specify that charges for metering extended services must also comply with clause 6.6(1)(e) of the *Electricity Industry (Metering) Code 2012*.

Required Amendment 2

Clause 5.12 must be amended to state that charges for metering extended services must also comply with clause 6.6(1)(e) of the *Electricity Industry (Metering) Code 2012*.

Target revenue

Western Power's initial proposal

171. Western Power's initial proposed target revenue for AA4 is set out in Table 2 and Table 3 below.

Table 2 Western Power AA4 initial proposed target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Proposed AA4 Total	Approved AA3 Total
Operating costs	93.8	84.2	83.1	84.6	84.6	430.3	578.6
Depreciation	113.7	117.2	126.9	138.3	144.3	640.3	562.1
Accelerated depreciation (redundant assets)	-	-	-	-	-	-	-
Return on regulated asset base	137.1	139.4	143.5	148.7	152.1	720.6	592.4
Return on working capital	1.1	1.5	1.6	1.8	2.0	8.0	4.9
Taxation	-	-	-	-	8.3	8.3	59.0
Deferred revenue recovery	4.8	4.8	4.8	4.8	4.8	23.8	21.0
Total before AA3 adjustments	**350.5**	**347.1**	**359.9**	**378.2**	**396.1**	**1,831.3**	**1,818.0**
Investment adjustment mechanism	-33.6	-	-	-	-	-33.6	-52.5
Service standard adjustment mechanism	13.4	-	-	-	-	13.4	6.8
Unforeseen events	5.5	-	-	-	-	5.5	-
D-factor	-	-	-	-	-	-	-
Gain sharing mechanism	18.2	19.3	21.6	22.5	22.0	103.7	-
K-factor	1.2	-	-	-	-	1.2	29.2
Total Revenue Building Blocks (unsmoothed)	**355.3**	**366.4**	**381.4**	**400.5**	**418.0**	**1,921.5**	**1,801.5**

	2017/18	2018/19	2019/20	2020/21	2021/22	Proposed AA4 Total	Approved AA3 Total
% change in unsmoothed building blocks	**22.4%[37]**	**3.1%**	**4.1%**	**5.0%**	**4.4%**	**-**	**-**

Note: Values in tables in this decision may not add to the indicated totals due to rounding.

Table 3 Western Power AA4 initial proposed target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Proposed AA4 Total	Approved AA3 Total
Operating costs	292.5	268.3	266.5	272.6	274.8	1,374.8	1,922.4
Depreciation	263.6	280.8	295.2	298.3	289.1	1,427.0	1,260.3
Accelerated depreciation (redundant assets)	-	-	-	-	-	-	4.3
Return on regulated asset base	255.4	266.2	276.6	288.1	293.9	1,380.3	929.2
Return on working capital	7.1	6.9	7.2	7.3	7.5	36.0	15.0
Taxation	48.1	56.3	60.8	58.0	56.0	279.4	207.9
Deferred revenue recovery	37.7	37.7	37.7	37.7	37.7	188.6	169.1
Tariff Equalisation Contribution	164.3	169.4	154.3	147.1	148.4	783.5	984.9
Total before AA3 adjustments	**1,068.7**	**1,085.6**	**1,098.3**	**1,109.1**	**1,107.4**	**5,469.6**	**5,493.1**

[37] Based on 2016/17 revenue of $290.1 million.

	2017/18	2018/19	2019/20	2020/21	2021/22	Proposed AA4 Total	Approved AA3 Total
Investment adjustment mechanism	-5.9	-	-	-	-	-5.9	2.1
Service standard adjustment mechanism	241.7	-	-	-	-	241.7	27.0
Unforeseen events	14.2	-	-	-	-	14.2	-
D-factor	8.8	-	-	-	-	8.8	-
Gain sharing mechanism	36.4	37.5	34.8	13.3	46.9	168.9	-
K-factor	36.6	-	-	-	-	36.6	54.2
Total Revenue Building Blocks (unsmoothed)	**1,400.6**	**1,123.2**	**1,133.2**	**1,122.5**	**1,154.4**	**5,933.8**	**5,576.4**
% change in unsmoothed building blocks	**13.4%**	**-19.8%**	**0.9%**	**-0.9%**	**2.8%**	-	-

172. Consistent with previous access arrangements, Western Power smoothed its proposed revenue requirement over the access arrangement period starting from 1 July 2018.

173. The maximum reference service revenue formula included in the current access arrangement included a correction factor that takes into account any difference between forecast maximum reference service revenue and the actual revenue earned in a year. Sections 5.6.8 and 5.7.8 of the current access arrangement states that the correction factor will apply in the first year of the next access arrangement period to adjust for any difference between the forecast and actual revenue for the financial years ending on 30 June 2017 and 30 June 2016, and in the second year of AA4 for the financial year ending on 30 June 2017.

174. Western Power's initial proposal stated: [38]

> Due to the one year delay in commencement of the AA4 revenue recovery, the revenue caps for 2017/18 are treated slightly differently. In the normal course of events, there would be a revised Price List and Price List Information produced for 2017/18, and these documents would outline the calculation of the revenue target for the year (using the formulae in the next section), including a calculation of the revenue adjustment factor (known as the k-factor). The versions of these documents (Appendix F.1 and F.2 to the proposed access arrangement) are the 2016/17 Price List reproduced, without any adjustments made for the k-factor. The 2016/17 Price List is adopted as the 2017/18 Price List absent a different Price List produced in April 2017 and approved by the ERA in May 2017 due to the delay to the AA4 process.

[38] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 238.

The k-factor adjustment takes into account the actual and forecast revenues recovered in previous financial years and adjusts the revenue target to ensure Western Power is recovering the required revenue amounts exactly. That is, if previous year's prices had over-recovered revenue then that over-recovery would be given back to customers through a lower revenue requirement in the next year, vice versa for under-recoveries.

To ensure the addition of this revenue adjustment doesn't result in lumpy price outcomes, the revenue model has been run with the k-factor for 2017/18 included as a building block. The revenue model also specifies revenue amounts for 2017/18 that reflect the most recently available revenue forecasts for the year, given that the 2016/17 [prices] will likely apply for the whole year. As the AA4 decision process continues, these numbers will be updated with more up-to-date forecasts.

175. Western Power also proposed deferring some revenue for transmission (and taking up more revenue in distribution) to limit its forecast increase in transmission prices to 10 per cent (in nominal terms).

176. Table 4 and Table 5 below show Western Power's initial proposed smoothed revenue targets, including the transmission revenue adjustment. The final two rows of each table show the target revenue (TR) and percentage change in target revenue values (Tx) required for the price control formula. The K-factor adjustment and tariff equalisation contribution are not included in these values.

Table 4 Western Power initial proposed smoothed target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue (from Table 2 above)	**355.3**	**366.4**	**381.4**	**400.5**	**418.0**	**1,921.5**	**1,686.9**
Revenue deferred[39]	-66.4	-54.4	-44.5	-38.4	-30.4	-234.1	-209.6
Proposed smoothed revenue	**288.8**	**312.0**	**337.0**	**362.1**	**387.5**	**1,687.4**	**1,477.3**
% change in smoothed revenue	-0.4%	8.0%	8.0%	7.5%	7.0%	-	-
Less K-factor	(1.2)					(1.2)	
Target revenue TRt	**287.6**	**312.0**	**337.0**	**362.1**	**387.5**	**1,686.2**	
Transmission Tx	**-**	**8.47%**	**8.01%**	**7.45%**	**7.03%**		

[39] The revenue deferred was calculated to result in a smoothed revenue profile based on a 10 per cent per annum increase in average charges.

Table 5 Western Power initial proposed smoothed target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue (from Table 3 above)	**1,400.6**	**1,123.2**	**1,133.2**	**1,122.5**	**1,154.4**	**5,933.8**	**5,246.8**
Revenue brought forward	66.4	54.4	44.5	38.4	30.4	234.1	209.6
Adjusted unsmoothed revenue	1,467.0	1,177.6	1,177.7	1,160.9	1,184.8	6,167.9	5,456.4
Smoothed revenue	**1,201.5**	**1,228.7**	**1,245.8**	**1,255.6**	**1,268.6**	**6,200.3**	**5,456.4**
% change in smoothed revenue	-2.7%	2.3%	1.4%	0.8%	1.0%		
Less K-factor	(36.6)					(36.6)	
Less TEC	(164.3)	(169.4)	(154.3)	(147.1)	(148.4)	(783.5)	
Target revenue DRt	**1,007.7**	**1,059.3**	**1,091.5**	**1,108.5**	**1,120.1**	**5,380.2**	
Distribution Dx	**-**	**5.86%**	**3.04%**	**1.55%**	**1.05%**		

177. Table 6, Table 7, and Table 8 below show the change in average charges based on Western Power's initial proposed smoothed target revenue and forecast energy volumes.

Table 6 Western Power initial forecast change in average charges for the transmission network ($ real June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed revenue ($ million)	290.1	288.84	311.98	336.97	362.08	387.54
Energy transported (GWh)	17,764	17,698	17,663	17,628	17,502	17,309
Average charge ($/MWh)	16.33	16.32	17.7	19.1	20.7	22.4
Annual % change	-	-0.08%	8.23%	8.23%	8.23%	8.23%

Table 7 Western Power initial forecast change in average charges for the distribution network ($ real June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed revenue ($ million)	1,235.0	1,201.54	1,228.73	1,245.82	1,255.61	1,268.59
Energy transported (GWh)	13,769	13,691	13,656	13,505	13,276	13,083
Average charge ($/MWh)	89.70	87.8	90.0	92.2	94.6	97.0
Annual % change	-	-2.16%	2.52%	2.52%	2.52%	2.52%

Table 8 Western Power initial forecast change in average charge ($ real June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed revenue ($ million)	1,525.2	1,490.4	1,540.7	1,582.8	1,617.7	1,656.1
Annual % change in total revenue	-	-2.3%	3.4%	2.7%	2.2%	2.4%
Average charge ($/MWh)	106.0	104.1	107.7	111.4	115.3	119.4
Annual % change in average charge	-	-1.8%	3.4%	3.5%	3.5%	3.5%

Draft Decision

178. The ERA's assessment of Western Power's determination of target revenue addressed the following matters:

- forecasts of demand for services;
- forecast operating expenditure
- amounts of actual and forecast capital expenditure and values of the regulated capital base at the commencement of AA4 and a notional regulated capital base over the term of AA4;
- a return on the regulated capital base;
- a return on working capital;
- an allowance for taxation; and
- adjustments to target revenue for AA4 to reflect certain cost and revenue outcomes for AA3.

179. The ERA has also assessed Western Power's actual and forecast costs for AA3 and AA4.

Target revenue

180. The ERA has determined values of target revenue taking into account determinations and required amendments of individual elements of target revenue. The values of target revenue for the transmission and distribution networks as determined by the ERA in its draft decision are set out in Table 9 and Table 10 below.

Table 9 ERA draft decision on target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Western Power proposal
Operating costs	80.8	79.2	78.4	79.7	79.4	**397.6**	430.3
Depreciation	111.4	116.3	123.9	133.0	137.4	**622.0**	640.3
Accelerated depreciation (redundant assets)	-	-	-	-	-	**-**	-
Return on regulated asset base	127.7	127.9	129.7	131.7	132.0	**649.0**	720.6
Return on working capital	1.1	1.6	1.8	2.0	2.4	**8.9**	8.0
Taxation	12.8	14.5	15.4	14.7	16.3	**73.7**	8.3
Deferred revenue recovery	4.5	4.5	4.5	4.5	4.5	**22.7**	23.8
Total before AA3 adjustments	**338.3**	**344.0**	**353.7**	**365.6**	**372.0**	**1,773.9**	**1,831.3**
Investment adjustment mechanism	(33.8)	-	-	-	-	**(33.8)**	(33.6)
Service standard adjustment mechanism	13.4	-	-	-	-	**13.4**	13.40
Unforeseen events	-	-	-	-	-	**-**	5.5
D-factor	-	-	-	-	-	**-**	-
Gain sharing mechanism	8.6	9.3	9.3	7.1	16.6	**50.9**	103.7
K-factor	1.2		-	-	-	**1.2**	1.2
Total Revenue Building Blocks (unsmoothed)	**327.7**	**353.4**	**363.0**	**372.8**	**388.7**	**1,805.6**	**1,921.5**
% change in unsmoothed building blocks	**12.9%**	**7.8%**	**2.7%**	**2.7%**	**4.3%**		

Table 10 ERA draft decision on target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Western Power proposal
Operating costs	263.8	258.7	256.0	260.2	259.2	**1,297.9**	1,374.8
Depreciation	256.0	275.5	286.9	287.0	276.0	**1,381.4**	1,427.0
Accelerated depreciation (redundant assets)							
Return on regulated asset base	236.5	245.4	254.2	264.0	269.3	**1,269.4**	1,380.3
Return on working capital	7.0	7.0	6.7	6.3	6.2	**33.2**	36.0
Taxation	52.5	52.9	48.1	39.4	37.7	**230.6**	279.4
Deferred revenue recovery	36.2	36.2	36.2	36.2	36.2	**181.1**	188.6
Tariff Equalisation Contribution	164.0	168.7	153.4	146.0	147.0	**779.0**	783.5
Total before AA3 adjustments	**1,016.0**	**1,044.4**	**1,041.5**	**1,039.1**	**1,031.6**	**5,172.6**	**5,469.6**
Investment adjustment mechanism	(8.3)					**(8.3)**	(5.9)
Service standard adjustment mechanism	241.0					**241.0**	241.7
Unforeseen events	-					**-**	14.2
D-factor	8.8					**8.8**	8.8
Gain sharing mechanism	27.4	29.3	29.3	22.5	52.7	**161.2**	168.9
K-factor	36.5					**36.5**	36.6
Total Revenue Building Blocks (unsmoothed)	**1,321.3**	**1,073.8**	**1,070.7**	**1,061.7**	**1,084.3**	**5,611.9**	**5,933.8**
% change in unsmoothed building blocks	**7.0%**	**-18.7%**	**-0.3%**	**-0.8%**	**2.1%**		

181. Western Power proposed to defer revenue from the transmission service and bring forward an equal amount of revenue for the distribution service to reduce the increase in charges for the transmission service. Stakeholder submissions included various views on this – transmission-only customers were concerned about large

increases to tariffs, while other stakeholders commented on equity issues arising from the transfer of revenue between services.

182. Approximately 95 per cent of Western Power's revenue comes from customers charged for both transmission and distribution services. Based on the *2016/17 Price List Information*, 58 customers are connected directly to the transmission network generating $78 million of revenue. These customers do not pay distribution charges.

183. Transferring revenue between services is inconsistent with the requirements of the Access Code, and the ERA considered there were alternatives to Western Power's proposal that were compliant and did not result in price shocks to customer groups.

184. Table 11 and Table 12 below show the ERA's draft determination of target revenue, smoothed in the same manner as Western Power's proposal (i.e. the net present value of the smoothed target revenue is equal to the unsmoothed target revenue) and the change in average charges (based on Western Power's forecast energy volumes), is equal in each year but without any reallocation of revenue between services. The forecast change in average charges is shown in Table 13, Table 14 and Table 15 below.

Table 11 ERA draft decision on smoothed target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue	327.7	353.4	363.0	372.8	388.7	1,805.6	1,598.8
Smoothed revenue	**286.0**	**320.9**	**360.1**	**402.0**	**447.0**	**1,816.0**	**1,598.8**
Less K-factor	(1.2)	-	-	-	-	(1.2)	-
Target Revenue (TRt)	**284.8**	**320.9**	**360.1**	**402.0**	**447.0**	**1,814.7**	**-**
Transmission Tx	-	12.69%	12.21%	11.63%	11.19%	-	-

Table 12 ERA draft decision on smoothed target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue	1,321.3	1,073.8	1,070.7	1,061.7	1,084.3	5,611.9	5,002.5
Smoothed revenue	**1,205.3**	**1,170.3**	**1,126.6**	**1,078.1**	**1,034.2**	**5,614.4**	**5,002.5**
Less K-factor	(36.5)	-	-	-	-	(36.5)	-
Less TEC	(164.0)	(168.7)	(153.4)	(146.0)	(147.0)	(779.0)	-
Target revenue (DRt)	**1,004.8**	**1,001.5**	**973.2**	**932.1**	**887.2**	**4,798.8**	**-**
Distribution Dx	-	-0.33%	-2.83%	-4.22%	-4.82%	-	-

Table 13 ERA draft decision on forecast change in average charges for the transmission network ($ real June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Unsmoothed revenue ($ million)	290.1	327.7	353.4	363.0	372.8	388.7
Smoothed revenue ($ million)	290.1	286.0	320.9	360.1	402.0	447.0
Energy transported (GWh)	17,764	17,698	17,663	17,628	17,502	17,309
Average charge ($/MWh)	16.3	16.2	18.2	20.4	23.0	25.8
Annual % change	**-**	**-1.05%**	**12.43%**	**12.43%**	**12.43%**	**12.43%**

Table 14 ERA draft decision on forecast change in average charges for the distribution network ($ real June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Unsmoothed revenue ($ million)	1,235.0	1,321.3	1,073.8	1,070.7	1,061.7	1,084.3
Smoothed revenue ($ million)	1,235.0	1,205.3	1,170.3	1,126.6	1,078.1	1,034.2
Energy transported (GWh)	13,769	13,691	13,656	13,505	13,276	13,083

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Average charge ($/MWh)	89.7	88.0	85.7	83.4	81.2	79.0
Annual % change	**-**	**-1.86%**	**-2.65%**	**-2.65%**	**-2.65%**	**-2.65%**

Table 15 ERA draft decision on forecast change in total average charge ($ real June 2017)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Total unsmoothed revenue ($ million)	1,525.2	1,649.0	1,427.2	1,433.7	1,434.5	1,473.0
Total smoothed revenue ($ million)	1,525.2	1,491.3	1,491.2	1,486.7	1,480.1	1,481.2
Annual % change in total revenue		**-2.2%**	**0.0%**	**-0.3%**	**-0.4%**	**0.1%**
Total average charge ($/MWh)	106.0	104.2	103.9	103.9	104.2	104.9
Annual % change	**-**	**-1.7%**	**-0.3%**	**0.0%**	**0.3%**	**0.7%**

185. As shown in Table 13 above, the annual change in average transmission charges, without any reallocation to distribution, is 12.43 per cent compared with Western Power's proposed annual increases of 8.23 per cent. However, the change in the average total charge is approximately 3 percentage points less than Western Power's proposal (comparing Table 15 with Table 8).

186. The difference between unsmoothed and smoothed revenue for 2021/22 is $8.2 million for the combined services, but transmission smoothed revenue is $58.3 million (15 per cent) higher than unsmoothed revenue. This is the reverse of the AA3 smoothing profile, where the smoothed transmission revenue in the final year was lower than the unsmoothed revenue.

187. A range of revenue smoothing profiles could meet the requirement of the Access Code to avoid price shocks, which Western Power should have considered. The ERA required Western Power to amend its target revenue to be consistent with the draft decision and review the smoothed target revenue to reduce the likelihood of price shocks in the next access arrangement period.

188. The draft decision stated that Western Power must also ensure its proposed prices avoid price shocks for individual reference services. The ERA considered the ability to rebalance tariffs within the side constraint in the price control formula would allow for this to be done.

189. The ERA's draft decision required the following amendment.

Draft Decision Required Amendment 4

The proposed access arrangement values for TRt and DRt 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 revised proposal

190. In its revised proposal, Western Power states it accepts the required amendment in principle with modifications:[40]

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

191. A breakdown of Western Power's revised proposed target revenue is set out in Table 16 and Table 17 below.

Table 16 Western Power AA4 revised proposed target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Revised Proposal Total	Initial Proposal Total	Draft Decision
Operating costs	94.0	84.8	85.1	87.8	88.1	439.8	430.3	397.6
Depreciation	110.1	118.0	127.7	138.3	143.9	638.0	640.3	622.0
Accelerated depreciation (redundant assets)								
Return on regulated asset base	131.0	132.8	137.4	142.3	144.1	687.6	720.6	649.0
Return on working capital	1.1	1.4	1.5	1.8	2.1	7.8	8.0	8.9
Taxation			2.7	21.1	32.4	56.2	8.3	73.7
Deferred revenue recovery	4.6	4.6	4.6	4.6	4.6	23.1	23.8	22.7
Total revenue before AA3 adjustments	**340.8**	**341.6**	**359.0**	**395.9**	**415.2**	**1,852.5**	**1,831.3**	**1,773.9**

[40] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 27.

	2017/18	2018/19	2019/20	2020/21	2021/22	Revised Proposal Total	Initial Proposal Total	Draft Decision
Investment adjustment mechanism	(33.5)					(33.5)	(33.6)	(33.8)
Service standard adjustment mechanism	13.4					13.4	13.4	13.4
Unforeseen events	4.6					4.6	5.5	-
D-factor								-
Gain sharing mechanism	13.1	13.8	13.8	9.1	17.0	66.7	103.7	50.9
K-factor	1.2					1.2	1.2	1.2
Total Revenue (unsmoothed)	**339.7**	**355.5**	**372.7**	**405.0**	**432.2**	**1,905.1**	**1,921.6**	**1,805.6**
% change in unsmoothed revenue		**4.7%**	**4.8%**	**8.7%**	**6.7%**			

Table 17 Western Power AA4 revised proposed target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Revised Proposal Total	Initial proposal Total	Draft Decision
Operating costs	292.3	268.5	269.8	278.8	281.3	1,390.7	1,374.8	1,297.9
Depreciation	258.3	281.6	292.7	293.4	289.4	1,415.5	1,427.0	1,381.4
Accelerated depreciation (redundant assets)	4.4	6.9	4.4			15.6	-	-
Return on regulated asset base	245.2	255.0	264.7	275.2	280.7	1,320.8	1,380.3	1,269.4
Return on working capital	7.1	6.7	6.7	6.7	6.9	34.1	36.0	33.2
Taxation	61.4	58.5	68.8	50.8	49.1	288.5	279.4	230.6
Deferred revenue recovery	36.8	36.8	36.8	36.8	36.8	184.2	188.6	181.1
Tariff Equalisation Contribution	164.0	190.9	153.4	146.0	147.0	801.2	783.5	779.0

	2017/18	2018/19	2019/20	2020/21	2021/22	Revised Proposal Total	Initial proposal Total	Draft Decision
Total revenue before AA3 adjustments	**1,069.5**	**1,104.9**	**1,097.3**	**1,087.7**	**1,091.2**	**5,450.6**	**5,469.6**	**5,172.6**
Investment adjustment mechanism	(5.9)					(5.9)	(5.9)	(8.3)
Service standard adjustment mechanism	241.3					241.3	241.7	241.0
Unforeseen events	14.2					14.2	14.2	-
D-factor	8.8					8.8	8.8	8.8
Gain sharing mechanism	41.6	43.6	43.6	28.7	53.7	211.2	169.0	161.2
K-factor	36.5					36.5	36.6	36.5
Total Revenue (unsmoothed)	**1,406.1**	**1,148.5**	**1,140.9**	**1,116.4**	**1,144.9**	**5,956.7**	**5,933.8**	**5,611.9**
% change in unsmoothed revenue		**-18.3%**	**-0.7%**	**-2.1%**	**2.6%**			

192. Western Power states it has looked at options to address the transmission price path issue:[41]

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

[41] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 28-29.

> timing of transmission and distribution revenue collection such that transmission tariff increases would be capped at 10 per cent per year.
>
> 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.
>
> 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).
>
> 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.

193. Western Power states it has considered the following options.

- Equal price changes resulting in annual nominal increases of 18.13 per cent per year.
- A step change resulting in a nominal increase of 49.66 per cent in 2018/19 and 2.5 per cent in the following three years.
- Deferring transmission revenue of $171 million to the AA5 period and annual nominal increases of 13 per cent each year. Unlike its proposed option in its initial proposal, this does not involve bringing forward collection of distribution revenue to offset the transmission revenue increase.

194. Western Power proposes adopting the final option listed above noting:

> 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.
>
> 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.

195. Western Power's revised proposed smoothed target revenue is set out in Table 18 and Table 19 below. As can be seen in the third row of Table 18, Western Power has deferred some of its proposed transmission revenue.

Table 18 Western Power revised proposed smoothed target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue (from Table 16 above)	**339.7**	**355.5**	**372.7**	**405.0**	**432.2**	**1,905.1**	**1,677.9**
Smoothed revenue	**284.3**	**312.2**	**380.8**	**438.5**	**502.9**	**1,918.7**	**1,677.9**
Proposed smoothed revenue after deferring revenue	**284.3**	**302.7**	**348.6**	**384.0**	**421.4**	**1,741.0**	**1,528.23**
% change in smoothed revenue		6.5%	15.2%	10.2%	9.7%		
Less K-factor	(1.2)					(1.2)	
Target revenue TRt	**283.1**	**302.7**	**348.6**	**384.0**	**421.4**	**1,739.8**	
Transmission Tx		**6.9%**	**15.2%**	**10.2%**	**9.7%**		

Table 19 Western Power revised proposed smoothed target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue (from Table 17 above)	**1,406.1**	**1,148.5**	**1,140.9**	**1,116.4**	**1,144.9**	**5,956.7**	**5,293.5**
Smoothed revenue	**1,193.5**	**1,192.3**	**1,204.2**	**1,197.2**	**1,193.2**	**5,980.4**	**5,293.5**
% change in smoothed revenue		-0.1%	1.0%	-06%	-0.3%		
Less K-factor	(36.5)					(36.5)	
Less TEC	(164.0)	(190.9)	(153.4)	(146.0)	(147.0)	(801.3)	
Target revenue DRt	**993.0**	**1,001.4**	**1,050.8**	**1,051.2**	**1,046.2**	**5,142.6**	
Distribution Dx		**0.8%**	**4.9%**	**0.0%**	**-0.5%**		

196. Table 20, Table 21 and Table 22 below show Western Power's proposed change in average charges based on Western Power's revised proposed smoothed target revenue and forecast energy volumes.

Table 20 Western Power revised forecast change in average charges for the transmission network ($ real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed revenue ($ million)	284.3	302.7	348.6	384.0	421.4
Energy transported (GWh)	17,698	17,663	17,628	17,502	17,309
Average charge ($/MWh)	16.1	17.1	19.8	21.9	24.3
Annual % change		6.7%	15.4%	11.0%	11.0%

Table 21 Western Power revised forecast change in average charges for the distribution network ($real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed revenue ($ million)	1,193.5	1,192.3	1,204.2	1,197.2	1,193.2
Energy transported (GWh)	13,691	13,656	13,505	13,276	13,083
Average charge ($/MWh)	87.2	87.3	89.2	90.2	91.2
Annual % change		0.2%	2.1%	1.1%	1.1%

Table 22 Western Power revised forecast change in average charge ($ real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed revenue ($ million)	1,477.7	1,495.0	1,552.8	1,581.2	1,614.6
Annual % change in total smoothed revenue		1.2%	3.9%	1.8%	2.1%
Average charge ($/MWh)	103.3	106.0	109.0	112.1	115.5
Annual % change in average charge		1.2%	4.3%	2.9%	3.1%

Submissions on draft decision

197. Submissions on the draft decision were primarily concerned with the transmission target revenue and charges for large users.

198. ATCO supported the ERA's draft decision that transferring revenue between services is inconsistent with the requirements of section 6.4 of the Access Code and the Access Code objective.[42]

> ATCO agrees that revenue should be recovered from network users within the access arrangement period and not deferred until future regulatory periods. This is consistent with the clear expectation in the regulatory framework that network businesses should

[42] ATCO Australia Submission Attachment 1, 14 June 2018, p. 1.

seek to align their required revenue with the forward-looking and efficient cost of providing regulated services during the access arrangement period – if revenue is deferred then the business is pushing the burden of cost recovery for current services onto future users of network services.

ATCO appreciates that in proposing to defer revenue Western Power was trying to minimise “price shock” for customers. However, as noted in ATCO’s December 2017 submission in response to the ERA’s Issues Paper, there are viable alternatives to Western Power’s proposed price path that would address “price shock” for customers, in this and the next access arrangement period, without compromising economic efficiency objectives. ATCO also noted that Western Power, as presented in Attachment 10.8 of their initial access arrangement submission, had prudently explored some of these options.

The ERA’s Draft Western Power Decision also requires Western Power to review the smoothed target revenue to reduce the likelihood of price shocks in the next access arrangement period (AA5).

In Western Power’s case, ATCO supports an approach similar to Option 3 in Attachment 10.8 as the best means of addressing “price shock” in AA4 and reducing the likelihood of price shocks into AA5.

Under this option, there would be a step-up in year one, followed by smaller increases in following years. In ATCO’s view, this option provides customers with pricing stability over the longer term, as it minimises the difference between smoothed revenue and target revenue in 20121/22 and sends more effective price signals during AA4 so as to promote the Access Code objective (economically efficient investment in, operation of and use of the Western Power network).

199. Perth Energy raised the following concerns about cost increases to large retail customers:[43]

Increases to transmission costs by 12% year on year from 2018 to 2022 represent a material increase to the cost of delivering energy via the transmission network. Neither the ERA nor Western Power has made any representation to market participants that there are benefits associated with this increase. Section 6.4(c) of the access code states that:

“The price control in an access arrangement must have the objectives of:

(c) Avoiding price shocks (that is, sudden material tariff adjustments between succeeding years)”

Perth Energy is of the view the ERA’s draft determination of transmission revenue increases of 57% over the AA4 period, which is approximately 12% per year would be considered a sudden material tariff adjustment between the AA3 period and the AA4 period. As such, In Perth Energy’s opinion the transmission price path over the AA4 period is considered to be a price shock and is therefore inconsistent with the requirements as set out in the Access Code.

As a result, Perth Energy and other retailers within the SWIS have been set the unfavourable task of notifying customers of significant price shocks to their transmission network costs over the AA4 period. This increase is particularly high for all customers on Reference Tariff 7 (RT7), Reference Tariff 8 (RT8), Transmission Reference Tariff 1 (TRT1) and Transmission Reference Tariff 2 (TRT2).

Typically when material cost increases occur in any industry within the economy, the first response by those paying the increase is ‘what is the associated benefit from my increased expenditure?’

Unfortunately, neither the ERA nor Western Power has made any representation to market participants that there are any benefits associated with the increases to

43 Perth Energy, p. 5.

transmission revenue. Examples of improvements that customers and retailers may find palatable would be:

- Increased reliability standards for transmission connected customers

- Less network constraints on the transmission network

- Transmission network upgrades that will enable new generation

- Improvement of network readiness to accommodate new technologies

Unfortunately, none of these expected benefits that could be assumed to come about through increased revenue regarding the transmission network over the AA4 period have been communicated through the Access Arrangement process. Given the silence of any associated benefits regarding increased transmission network revenue, Perth Energy has come to the conclusion there is no benefit arising from the price shocks facing transmission connected customers.

Perth Energy notes that these substantial increases are being proposed at a time when all other participants in the electricity market are making stringent efforts to reduce prices to customers.

200. Perth Energy raises the following concerns about cost increases to power generators:[44]

As the owner of a gas fired power station, Perth Energy finds itself in an unfortunate situation where it will have to accept a significant increase to transmission network costs during 2018 – 2021 for its power station with no mechanism in the current market rules to recover that drastic increase in cost.

For a market generator there are two avenues through which to recover the cost of generating power. The energy market and the capacity market. As the capacity price is set three years in advance, the transmission price shocks proposed throughout the AA4 period have not been factored into the capacity revenue a generator can expect to receive. The escalation factor in the calculation of the Benchmark Reserve Capacity Price with respect to Western Power transmission costs has been set at 0.4% for each year from 2018 through to 2021. Similarly, with respect to the energy market, power generators must bid at short run marginal cost. The ERA released guidelines on what costs would be considered short run marginal cost earlier this year. As network costs are deemed fixed costs, under the balancing submission guidelines released by the ERA, market generators are not able to recover this cost through changing their bids into the energy market. The price shocks proposed through the AA4 draft determination have created a situation where power generators will have to carry network losses as there is no mechanism to recover the transmission cost increases.

201. Perth Energy challenges the ERA to:[45]

- Reconcile how a 12 per cent year on year price increase to transmission connected customers does not constitute a price shock over the AA4 period
- Clarify what tangible benefits transmission connected customers are receiving from the price shock that is a direct result of transmission price increases.
- Reconcile how a transmission price increase with no improvement in service quality is consistent with access code objective of promoting competition downstream of the network.
- Reconcile how the ERA as an organisation have created the situation where significant cost increases are not recoverable by market generators with the access code objective of promoting competition upstream of the network.

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44 Perth Energy, p. 6.

45 Perth Energy, *Submission to the Economic Regulation Authority regarding ERA's Draft Decision Regarding Western Power's Access Arrangement Proposal (2018-2022)*, 30 May 2018, p. 6.

202. Summit Southern Cross Power considers that transmission target revenue attributable to the Mid-West Energy Project should not be allocated to existing generators as they have not benefited from that investment. The submission refers to the $233 million of net benefits taken into account when it was determined that the proposed expenditure for the new transmission line met the new facilities investment test, and questions how those benefits are passed through to consumers.

> Western Power's tariffs are set via a complex arrangement whereby the allocation of allowable target revenue is attributed to a number of cost pools. Cost pools, at least for the transmission network, are derived using the Gross Optimised Deprival Value (GODV) for the suite of assets contained within that pool, as a proportion of the total asset pool. The proportion of allowable revenue attributed to the cost pools is then spread over tariff classes in a manner specified in the Price List Information details.
>
> There are however some tariff classes where it is clear that the customers within that tariff class do not benefit from a large portion of 'net benefits' of the type assessed under the NFIT. While it could be argued that every different tariff class derives a varying degree of value from such net benefits, a clear distinction can be made between generators and loads. Loads will eventually benefit from lower cost of supply. Generators do not. In fact, existing generators are typically disadvantaged by lower-cost, new entrant generation.
>
> Increasing the generator network tariffs (such as the TRT2 tariff, for transmission connected generators) is a transfer of wealth from existing generators to:
>
> - the generators connecting to the new transmission assets;
> - the loads that require the new transmission assets; and
> - Western Power.
>
> There is a likely requirement for further network augmentation in the north-country region to connect the long queue of new renewable projects. It is also likely that 'net benefits' will play a role in the assessment of those future augmentations, where the benefits of connecting new low-cost generation will be attributed to end users. It is thus important that the ERA makes a distinction between which tariff classes the net benefits accrue to, otherwise this transfer in wealth may become significant over time.

203. The submission suggests that the component of target revenue associated with the net benefits attributed to the Mid-West Energy Project should be excluded from the revenue recovered from generators (including transmission and distribution connected generators).

Final Decision

204. The ERA has not approved Western Power's proposed expenditure and other elements of target revenue. The values of target revenue for the transmission and distribution networks determined by the ERA in its final decision are set out in Table 23 and Table 24 below.

Table 23 ERA final decision on target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Final Decision Total	Western Power revised proposal	Draft Decision
Operating costs	82.1	80.6	80.3	81.5	79.7	404.3	439.8	397.6
Depreciation	109.7	115.2	122.0	128.8	132.2	608.0	638.0	622.0
Accelerated depreciation (redundant assets)	-	-	-	-	-	-		
Return on regulated asset base	122.9	123.5	125.9	128.0	127.8	628.1	687.6	649.0
Return on working capital	1.1	1.4	1.4	1.9	2.3	8.0	7.6	8.9
Taxation	12.2	10.3	10.5	10.4	12.9	56.4	56.2	73.7
Deferred revenue recovery	4.4	4.4	4.4	4.4	4.4	22.2	23.1	22.7
Total before AA3 adjustments	**332.5**	**335.5**	**344.7**	**355.1**	**359.3**	**1,727.0**	**1,852.5**	**1,773.9**
Investment adjustment mechanism	(35.8)	-	-	-	-	(35.8)	(33.5)	(33.8)
Service standard adjustment mechanism	13.3	-	-	-	-	13.3	13.4	13.4
Unforeseen events	-	-	-	-	-	-	4.6	-
D-factor	-	-	-	-	-	-	-	-
Gain sharing mechanism	8.6	9.3	9.3	7.1	16.6	50.9	66.7	50.9
K-factor	1.2	-	-	-	-	1.2	1.2	1.2
Total Revenue Building Blocks (unsmoothed)	**319.9**	**344.8**	**354.0**	**362.2**	**375.9**	**1,756.7**	**1,905.1**	**1,805.6**

Table 24 ERA final decision on target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Final Decision Total	Western Power revised proposal	Draft Decision
Operating costs	271.4	268.4	268.3	273.6	270.0	1,351.8	1,390.7	1,297.9
Depreciation	258.3	274.9	278.6	269.4	262.5	1,343.6	1,415.5	1,381.4
Accelerated depreciation (redundant assets)	4.4	6.9	4.4	-	-	15.6	15.6	-
Return on regulated asset base	229.3	237.6	245.5	254.7	260.3	1,227.3	1,320.8	1,269.4
Return on working capital	6.8	6.5	6.3	5.9	5.8	31.3	34.1	33.2
Taxation	74.8	31.4	29.6	23.9	28.3	188.0	288.5	230.6
Deferred revenue recovery	35.6	35.6	35.6	35.6	35.6	177.8	184.2	181.1
Tariff Equalisation Contribution	164.0	190.9	153.4	146.0	147.0	801.2	801.2	779.0
Total before AA3 adjustments	**1,044.6**	**1,052.1**	**1,021.5**	**1,009.1**	**1,009.4**	**5,136.6**	**5,450.6**	**5,172.6**
Investment adjustment mechanism	(7.1)	-	-	-	-	(7.1)	(5.9)	(8.3)
Service standard adjustment mechanism	240.7	-	-	-	-	240.7	241.3	241.0
Unforeseen events	-	-	-	-	-	-	14.2	-
D-factor	8.7	-	-	-	-	8.7	8.8	8.8
Gain sharing mechanism	27.4	29.3	29.3	22.5	52.7	161.2	211.2	161.2
K-factor	36.4	-	-	-	-	36.4	36.5	36.5
Total Revenue Building Blocks (unsmoothed)	**1,350.6**	**1,081.4**	**1,050.8**	**1,031.7**	**1,062.0**	**5,576.6**	**5,956.7**	**5,611.9**

205. In its initial proposal, Western Power proposed to defer revenue from the transmission service and bring forward an equal amount of revenue for the distribution service to reduce the increase in charges for the transmission service. Stakeholder submissions included various views on this – transmission-only customers were concerned about large increases to tariffs, while other stakeholders commented on equity issues arising from the transfer of revenue between services.

206. In its draft decision the ERA considered that transferring revenue between services was inconsistent with the requirements of the Access Code, and there were alternatives to Western Power's proposal that were compliant and did not result in price shocks to customer groups.

207. In its revised proposal, Western Power has proposed deferring some of its proposed transmission target revenue to reduce the increase in average transmission charges during the period. Similar to the draft decision on Western Power's proposed transfer of revenue between services, the ERA considers that deferring revenue to a subsequent access arrangement period is inconsistent with the requirements of the Access Code.

208. Table 25 and Table 26 below show the ERA's final determination of target revenue, smoothed in the same manner as Western Power's proposal (i.e. the net present value of the smoothed target revenue is equal to the unsmoothed target revenue) and the change in average charges (based on Western Power's forecast energy volumes), is equal in each year, as can be seen in Table 27 and Table 28 below.

209. However, the date assumed for the first price change is 1 February 2019 rather than Western Power's proposed date of 1 November 2018 as discussed in the introduction.

Table 25 ERA final decision on smoothed target revenue for the transmission network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue	319.9	344.8	354.0	362.2	375.9	1,756.7	1,561.7
Smoothed revenue	280.9	292.2	355.2	397.3	442.6	1,768.3	1,561.7
Less K-factor	(1.2)						
Target Revenue (TRt)	**279.7**	**292.2**	**355.2**	**397.3**	**442.6**		
Transmission Tx		4.47%	21.54%	11.86%	11.42%		

Table 26 ERA final decision on smoothed target revenue for the distribution network ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA4 Total at Present Value
Unsmoothed Revenue	1,350.6	1,081.4	1,050.8	1,031.7	1,062.0	5,576.6	4,993.7
Smoothed revenue	1,188.2	1,161.8	1,120.8	1,077.4	1,038.3	5,586.5	4,993.7
Less K-factor	(36.4)						
Less TEC	(164.0)	(190.9)	(153.4)	(146.0)	(147.0)		
Target revenue (DRt)	**987.8**	**970.9**	**967.4**	**931.5**	**891.3**		
Distribution Dx		-1.72%	-0.35%	-3.72%	-4.31%		

210. The smoothed transmission target revenue has historically been more volatile than distribution target revenue.

211. The difference between unsmoothed and smoothed revenue for 2021/22 is $42.5 million (3 per cent) for the combined services, but transmission smoothed revenue is $66.7 million (18 per cent) higher than unsmoothed revenue. This is the reverse of the AA3 smoothing profile, where the smoothed transmission revenue in the final year was lower than the unsmoothed revenue.

212. As can be seen in Table 25, the smoothed revenue values for 2017/18 and 2018/19 are below the unsmoothed revenue values, the smoothed and unsmoothed values in 2019/20 are very close and then the smoothed values in 2020/21 and 2021/22 are higher than the unsmoothed values. The increasing gap between the smoothed and unsmoothed values reflects both the need to recover the deficit from the earlier years – that is the first two years when smoothed revenue is less than unsmoothed revenue - and increases in the unsmoothed revenue over the AA4 period.

213. As demonstrated in Western Power's modelling, the gap in the final year can be reduced by a step change increase in 2018/19 followed by flat charges, but this results in the increase for 2018/19 more than doubling. The ERA considers this would be too much of a price shock and it is better to maintain the annual smoothing profile used in previous access arrangements.

214. The forecast change in average charges is shown in Table 27, Table 28 and Table 29 below.

Table 27 ERA final decision on forecast change in average charges for the transmission network ($ real June 2017)

	2017/18	July 2018 to Jan 2019	Feb 2019 to June 2019	2019/20	2020/21	2021/22
Unsmoothed revenue ($ million)	319.9	201.1	143.7	354.0	362.2	375.9
Smoothed revenue ($ million)	280.9	163.6	128.7	355.2	397.3	442.6
Energy transported (GWh)	17,698	10,303	7,360	17,628	17,502	17,309
Average charge ($/MWh)	15.9	15.9	17.9	20.1	22.7	25.6
% change			**12.7%**	**12.7%**	**12.7%**	**12.7%**

Table 28 ERA final decision on forecast change in average charges for the distribution network ($ real June 2017)

	2017/18	July 2018 to Jan 2019	Feb 2019 to June 2019	2019/20	2020/21	2021/22
Unsmoothed revenue ($ million)	1,350.6	630.8	450.6	1,050.8	1,031.7	1,062.0
Smoothed revenue ($ million)	1,188.2	691.4	470.41	1,120.8	1,077.4	1,038.3
Energy transported (GWh)	13,691	7,966	5,690	13,505	13,276	13,083
Average charge ($/MWh)	86.8	86.8	84.9	83.0	81.2	79.4
% change			**-2.2%**	**-2.2%**	**-2.2%**	**-2.2%**

Table 29 ERA final decision on forecast change in total average charge ($ real June 2017)

	2017/18	July 2018 to Jan 2019	Feb 2019 to June 2019	2019/20	2020/21	2021/22
Total unsmoothed revenue ($ million)	1,670.5	831.9	594.2	1,404.8	1,393.8	1,437.9
Total smoothed revenue ($ million)	1,469.2	854.9	599.1	1,475.7	1,474.3	1,480.4
Annual % change in total revenue					**-0.09%**	**0.42%**
Total average charge ($MWh)	102.7	100.8	102.8	103.1	103.9	104.9
% change			**0.1%**	**0.3%**	**0.7%**	**1.0%**

215. Western Power's tariffs have not been amended since 1 July 2016. As set out in Table 29 above, the forecast change in overall average charges on 1 February is 0.1 percentage points above CPI, followed by 0.3 percentage points above CPI on 1 July 2019. The forecast change in the average charge is slightly higher in the following two years – 0.7 percentage points above CPI in 2020/21 and 1.0 percentage point above CPI in 2021/22.

216. As set out in Table 27 above, average transmission charges are forecast to change by 12.6 percentage points above CPI and Table 28 shows average distribution charges are forecast to change by 2.2 percentage points below CPI.

217. The ERA's forecast change for transmission charges of 12.7 per cent (real) is higher than Western Power's – 11.0 per cent – because Western Power proposes to defer some revenue to AA5. The ERA's forecast change for distribution charges of a real decrease of 2.2 per cent is lower than Western Power's 1.1 per cent increase. The ERA's forecast overall change in charges is also below Western Power's proposal.

218. As noted in the draft decision, approximately 95 per cent of Western Power's revenue comes from users charged for both transmission and distribution services. Prices for these users will generally be in line with the overall average change in charges - between 0.1 per cent and 1.0 per cent above inflation.

219. However, charges for customers connected directly to the transmission network will generally be in line with the average change in transmission charges – 12.7 per cent. Based on the *2016/17 Price List Information*, 58 customers are connected directly to the transmission network generating $78 million of revenue. Revenue recovered from generators was $46.1 million and $31.9 million from transmission connected loads.

220. The draft decision required Western Power to ensure its proposed prices avoided price shocks for individual reference services. The ERA considered this could be managed using the flexibility within the side constraint in the price control formula.

221. As explained above, in its revised proposal, Western Power proposed reducing the transmission charge increases by deferring a portion of transmission revenue to AA5. It also applied a relatively lower charge increase to the transmission connected

customers by utilising the side constraint resulting in the transmission connected user transmission charges increasing by approximately 2 per cent less than distribution connected users transmission charges. However, this still resulted in the transmission connected customers charges increasing much more than other customer groups.

222. Stakeholder submissions on Western Power's initial proposal and the ERA's draft decision raise concerns that this is inconsistent with the requirements of Access Code to avoid price shock.

223. Arguably, as these customers experienced annual reductions in charges during AA3 in the order of 10 per cent, the forecast increases could be seen as a correction. However, large increases and decreases are both a form of price shock.

224. As noted above, in the draft decision, the ERA had considered the prices could be managed by using the flexibility within the side constraint. However, the current side constraint only permits charges within each service to vary by a maximum of two per cent from the average change in charges.

225. As outlined above, Summit Southern Cross Power raises concerns that the current method for allocating costs to customer groups has resulted in costs being allocated to generators that they receive no benefit for. Perth Energy submits there appear to be no benefits associated with the increased charges and that, the increased transmission network charges might not be recoverable through either the reserve capacity price[46] or energy prices.[47]

226. As discussed later in Pricing Methods, Price List and Price List Information, although the pricing methods used by Western Power are compliant with the Access Code requirements, improvements could be made to develop more efficient prices. There are also arbitrary allocations between transmission and distribution services for corporate costs, indirect costs and gain share mechanism rewards.

227. Although there is no doubt about Western Power's total costs, there is no uniquely "best" allocation of overhead costs between the transmission and distribution services, and between tariff groups. For the majority of users this does not matter as they are charged for both transmission and distribution services so any over allocation in one service is offset by an under-allocation in the other.

228. However, in the case of transmission connected users, there is no offsetting factor for any misallocation. Applying large increases (or decreases) in charges to users based on relatively uncertain values is concerning.

229. The total value of the customers affected by a possible misallocation of costs – that is customers who only receive one service- is only five per cent of the total customer base. So the effect of any misallocation between services, would be very small on the 95 per cent of customer charges for combined services. For example, a 10 per cent misallocation would affect the main customer base by 0.5 per cent.

[46] As the 2018 to 2021 prices were set before the network charge information was available.

[47] Because network charges are not a short run marginal cost and therefore should not be included in prices offered in the wholesale energy market.

230. In the case of network charges for generators, ultimately these costs should pass through to consumers. This occurs either through the generator passing on the costs when it sells its energy, or, through the network costs allocated to loads.

231. Given that there is no uniquely best allocation of overhead costs between services and the small effect any misallocation has on the majority of customers, the ERA considers the best way to manage these issues would be to ensure the overall change in charges (that is transmission and distribution combined or transmission only for the customers connected to the transmission network) for each tariff group is constrained to be within a certain margin of the overall average change in charges. This can be achieved by applying the existing side constraint formula to the combined charge rather than separately to transmission and distribution. The existing side constraint formula places a limit that individual tariffs cannot increase by more than two percentage points above the average.

232. Applying the side constraint to the overall charge rather than each service, will enable transmission costs to be reallocated across customer groups, with less cost allocated to transmission connected customers and more to customers receiving combined services.

233. Total charges for each service will still be set to collect the target revenue determined for each service, and the costs attributable to each customer group will continue to be allocated by Western Power using its cost allocation processes. When allocating costs, Western Power must ensure the prices are set between stand-alone and incremental cost so there is no cross subsidisation between customer groups.

234. Applying the side constraint at the end of the process to the overall change for each tariff then ensures no tariff groups are subject to price shock.

235. This will result in average charges for each tariff group increasing by no more than two percentage points above the overall average shown in Table 29 above.

Required Amendment 3

The proposed access arrangement must be amended to reflect the ERA's final decision on target revenue.

The side constraint for each tariff should be applied to the overall change in tariff (transmission and distribution combined) rather than separately to each service as it currently is.

Forecast demand for services

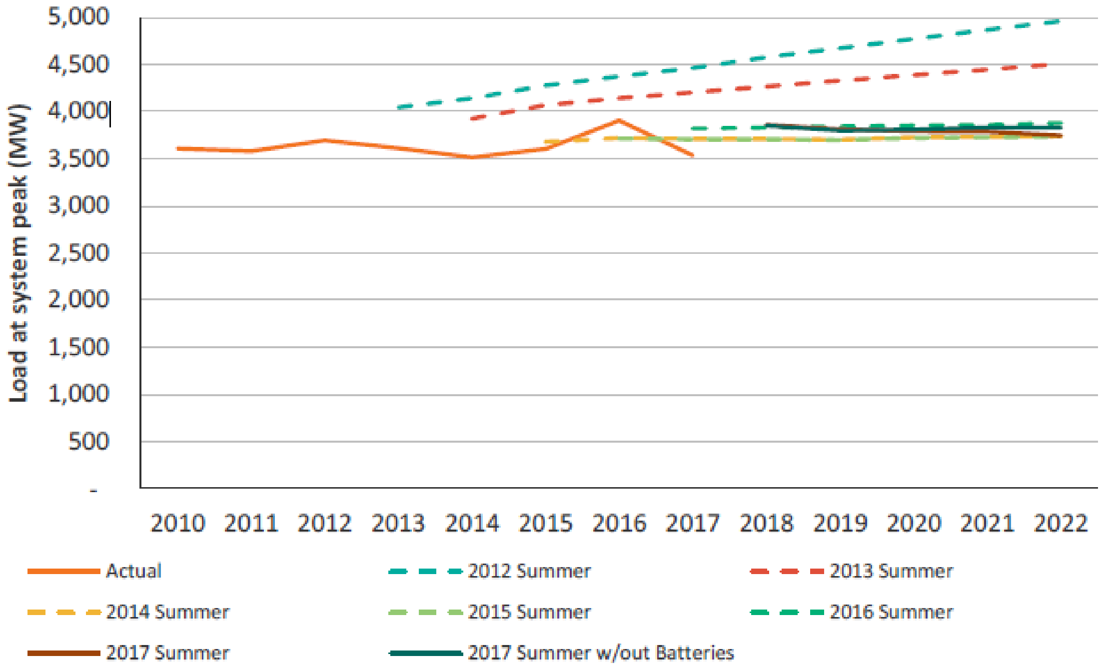
Western Power's initial proposal

236. For each year of AA4 Western Power forecast a:

- 1.6 per cent increase in customer numbers;
- 0.6 per cent decline in network peak demand; and
- 0.4 per cent reduction in energy consumption.

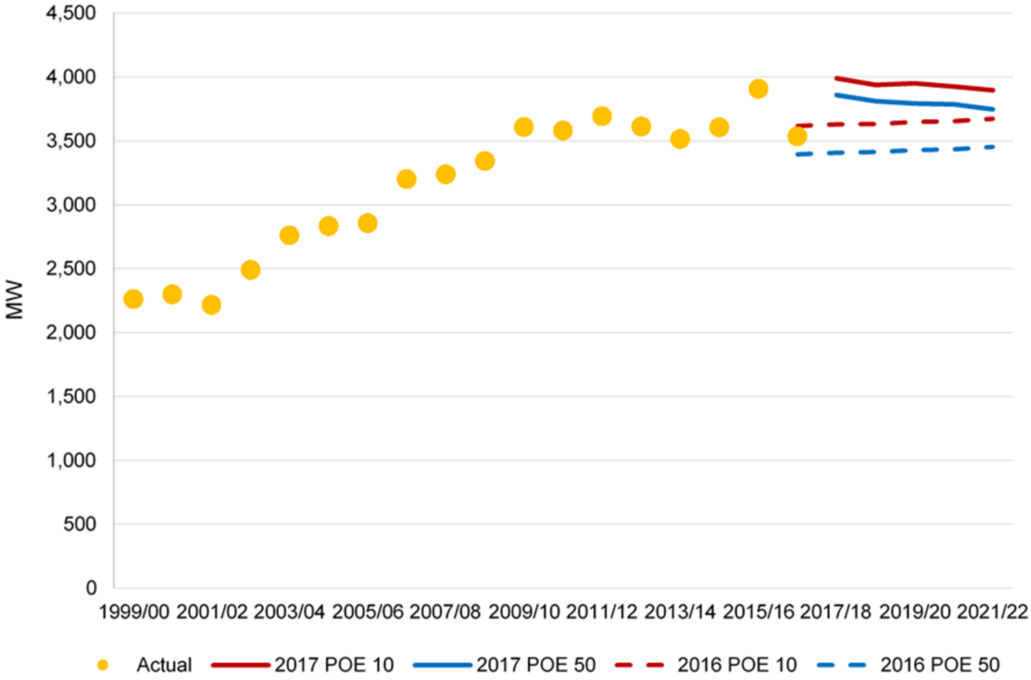
237. This is the first time Western Power has forecast a decline in peak demand and energy consumption. Figure 1 and Figure 2 below compares the peak demand forecasts between 2012 and 2017.

Figure 1 Western Power comparison of network peak demand forecasts between 2012 and 2017



Source: Western Power Access Arrangement Information Attachment 7.3, 2 October 2017, Figure 2.3, p. 7.

Figure 2 **Western Power actual and forecast POE 10 and POE 50 for network maximum demand**



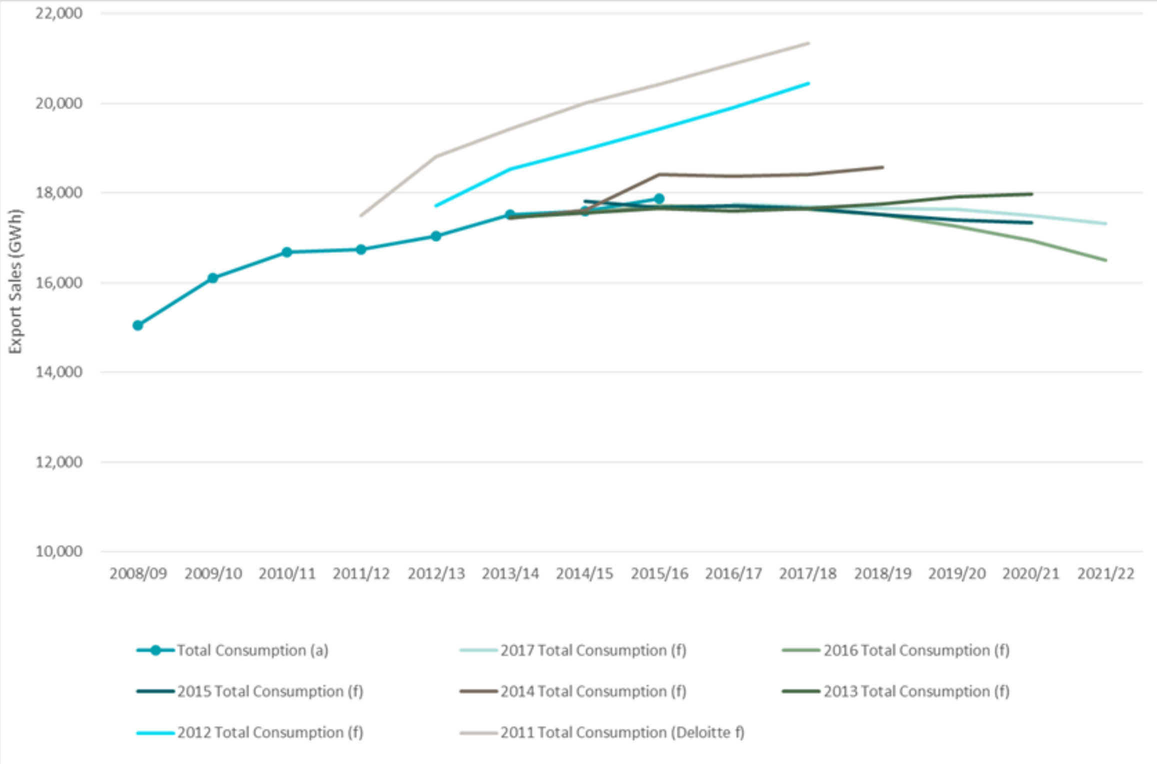
Source: Western Power data and GHD analysis

238. As shown in the (above) figures:

- Peak demand forecasts reduced significantly between 2012 and 2014. The 2015 forecast was similar to the 2014 forecast and there was a small increase in the 2016 forecast (Figure 1).
- The forecasts predict a higher peak demand for 2017/18, compared with the 2016 forecast, followed by a decline over the next four years. Despite the decline, the 2017 forecast peak demand by the end of the period is above the 2016 forecast (Figure 2).

239. The decline in forecast energy consumption is shown Figure 3 below.

Figure 3 Western Power actual and forecast energy consumption



240. Western Power had based its proposed capital expenditure on the 2016 forecast because the timing of its planning cycle meant the 2017 forecasts were not available at the time it developed its capital expenditure proposal. However, Western Power had used the 2017 forecasts for its operating expenditure and network prices because this only required updates to values in models.

241. Western Power noted that it had compared the 2017 forecasts to the 2016 forecasts at a high level to ensure that its network investment plans would not require significant changes. It also noted that the capacity expansion forecasts did not factor in the effects of forthcoming closures of some of Synergy's generation fleet.

242. While Western Power considered investment in the distribution network was typically more sensitive to load growth, it noted that an early assessment of the difference between the 2016 and 2017 demand forecasts would only result in a small adjustment, or deferral of load dependent distribution projects. Western Power stated that any necessary adjustments to the AA4 distribution capital expenditure forecast would be assessed as part of its annual planning cycle and factored into its response to the ERA's draft decision.

Submissions on Western Power's initial proposal

243. Submissions from Alinta Energy, the Australian Energy Council, Emergent Energy and Synergy all commented on Western Power's demand forecasts. The following matters were raised.

- The level of detail provided by Western Power to substantiate its demand forecasts – submissions from the Australian Energy Council and Synergy considered the level of detail provided was insufficient.

- The forecast decline in demand and the effect of solar photovoltaic (**PV**) systems and batteries – submissions from Alinta Energy and Emergent Energy noted the forecast decline in demand, the uncertainties of the effect of PV systems and batteries on future demand and the possible under-utilisation of assets.

Draft decision

244. Section 4.3(d) of the Access Code requires Western Power's access arrangement information to include information that details and supports its assumptions about system capacity and volumes.

245. Section 7.3(a) of the Access Code establishes an objective for the determination of reference tariffs (pricing methods) – the reference tariffs must have the objective of recovering the forward-looking efficient costs of providing reference services. Forecasts of demand for services are necessary to determine whether the reference tariffs proposed by Western Power meet this objective.

246. In making its assessment, the ERA considered the advice provided by its technical consultant GHD, who undertook a review of Western Power's 2017 demand forecast and concluded that the basis of the forecast was sound and reasonable.

247. As identified by Synergy in its submission on Western Power's proposal, AEMO also prepares annual forecasts of demand, which are published in its annual *Electricity Statement of Opportunities*. The ERA considered how Western Power's forecasts compared with the latest demand forecasts prepared by AEMO. It noted:

    - AEMO forecasts the maximum sent-out electricity entering the South West Interconnected System (SWIS), which includes all SWIS customers and all losses.
    - Western Power's forecast only includes demand on the parts of the SWIS owned by Western Power, and excludes losses on the transmission network.
    - Consequently, AEMO's forecasts will be higher than those produced by Western Power. However, comparing trends over time was still a useful exercise because the underlying factors would be similar.

248. Figure 4 and Figure 5 below compares Western Power's and AEMO's peak demand and energy consumption forecasts respectively. In both cases, Western Power's forecasts are trending downwards, while AEMO's forecasts are trending upwards.

Figure 4 Western Power actual and forecast network demand and AEMO SWIS maximum demand

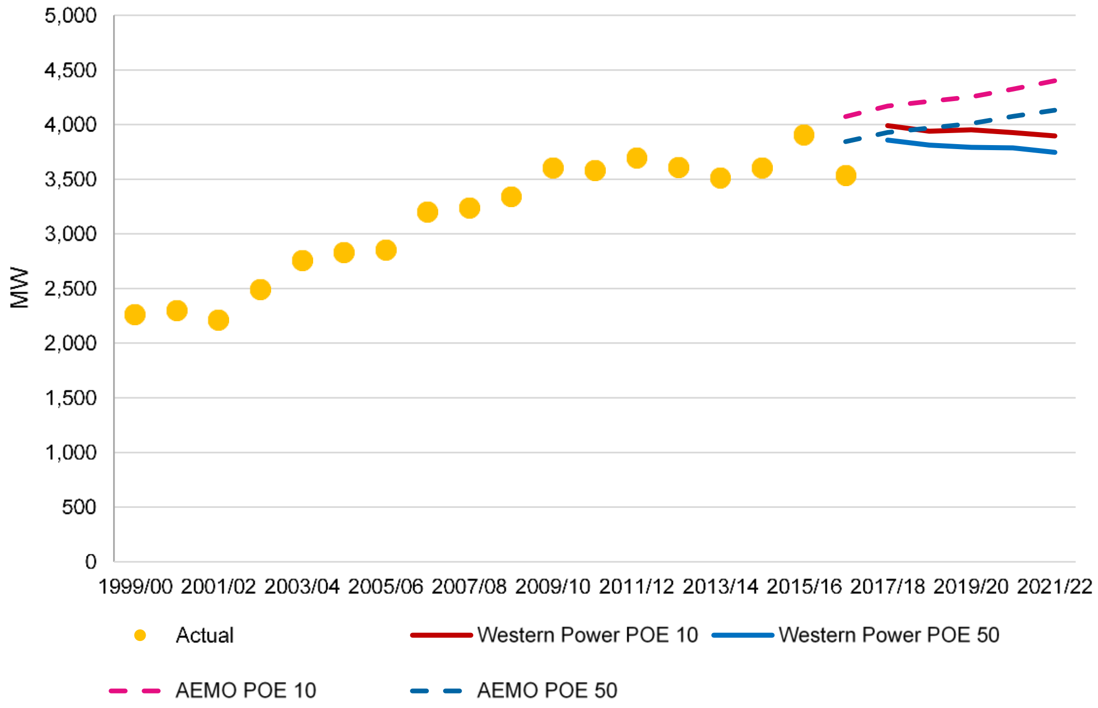
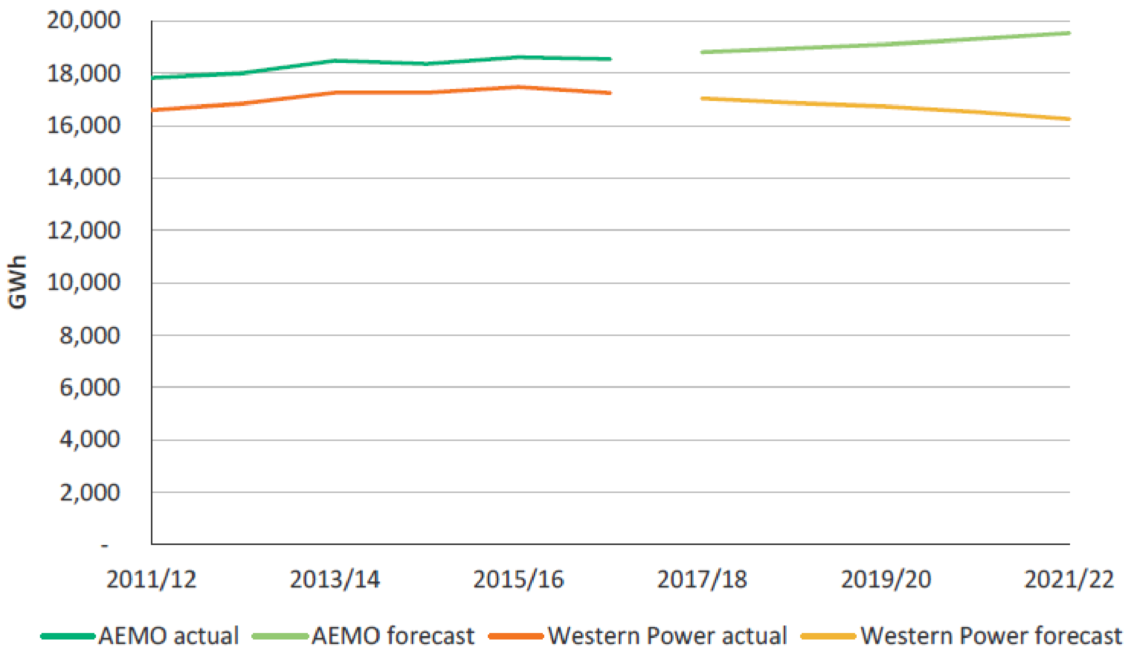


Figure 5 Comparison of Western Power and AEMO forecasts of total energy consumption



Source: Western Power Access Arrangement Information Attachment 7.3, 2 October 2017, Figure 4.2, p. 15.

249. As set out in Table 30 below different modelling approaches were used, which may have led to some differences. Most significantly, Western Power based its forecasts on more conservative assumptions of economic growth, numbers of customers and consumption (particularly in the case of residential consumption where it forecast a

reduction of 2.1 per cent per annum compared with AEMO's assumed 0.3 per cent per annum growth).

Table 30 Differences in forecast methods used by AEMO and Western Power

Reason	AEMO	Western Power
Model Choice	Top down ordinary least squares structural models – typically good for identifying the cause of variation but have poor predictive capacity	Bottom up time series models with exogenous variables – less useful for identifying cause but much better predictive capacity Forecasting network exports and imports separately Top down reconciliation using generalised additive model spline structural models
Variable Selection	Excluded all negatively correlated inputs (price, energy efficiency)	Far greater consideration for price and energy efficiency
Technology	AEMO and WP took very similar views on PV, battery and Electric Vehicle uptake, although the assumptions on impact vary	
Block Loads (large new customers)	AEMO and WP took a very similar view on block loads	
Economic Growth	3.3% p.a. (10yr)	1.8% p.a. (5yr)
Population/Customers	WA tomorrow (ignores economic downturn)	Regression on customer numbers
Residential Consumption	0.3% p.a. (10yr)	-2.1% p.a. (5yr)
Non-Residential Consumption	0.8% p.a. (10yr)	0.1% p.a. (5yr)

Source: Western Power Access Arrangement Information Attachment 7.3, 2 October 2017, Table 2.3, p. 9.

250. The ERA also considered Western Power's forecasting history. In previous access arrangement proposals, Western Power generally over-forecast demand. Figure 6 and Figure 7 below compares the demand forecasts underpinning the approved target revenues for the first (AA1), second (AA2) and third (AA3) access arrangement periods with actual demand for the transmission and distribution network respectively.

Figure 6 Comparison of Western Power access arrangement demand forecasts and actual demand for transmission

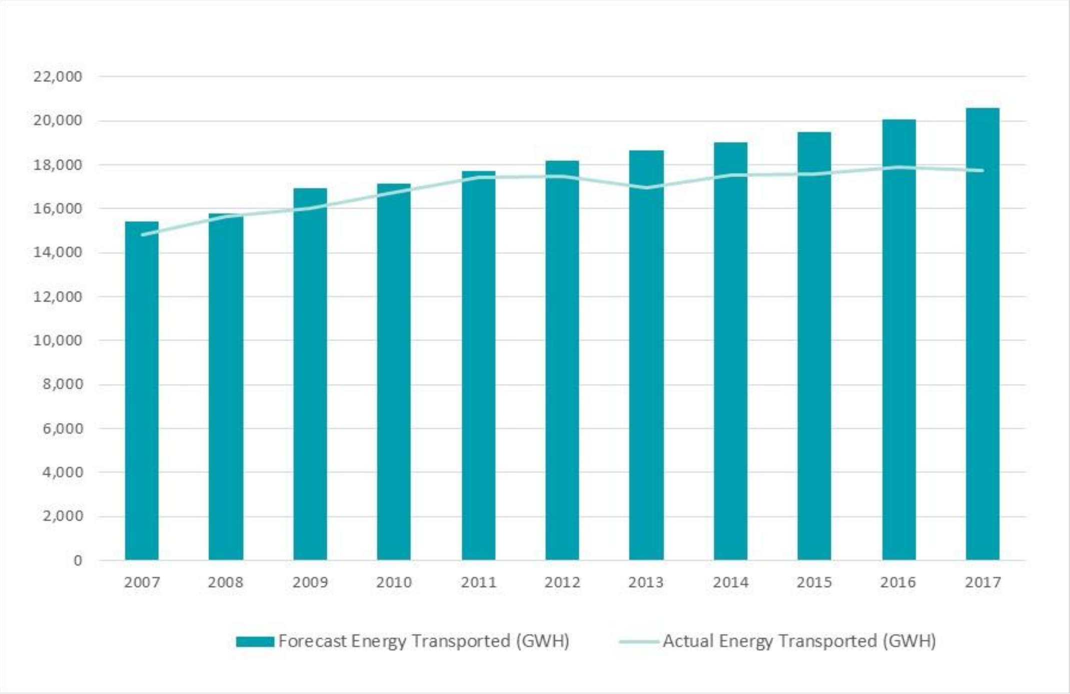
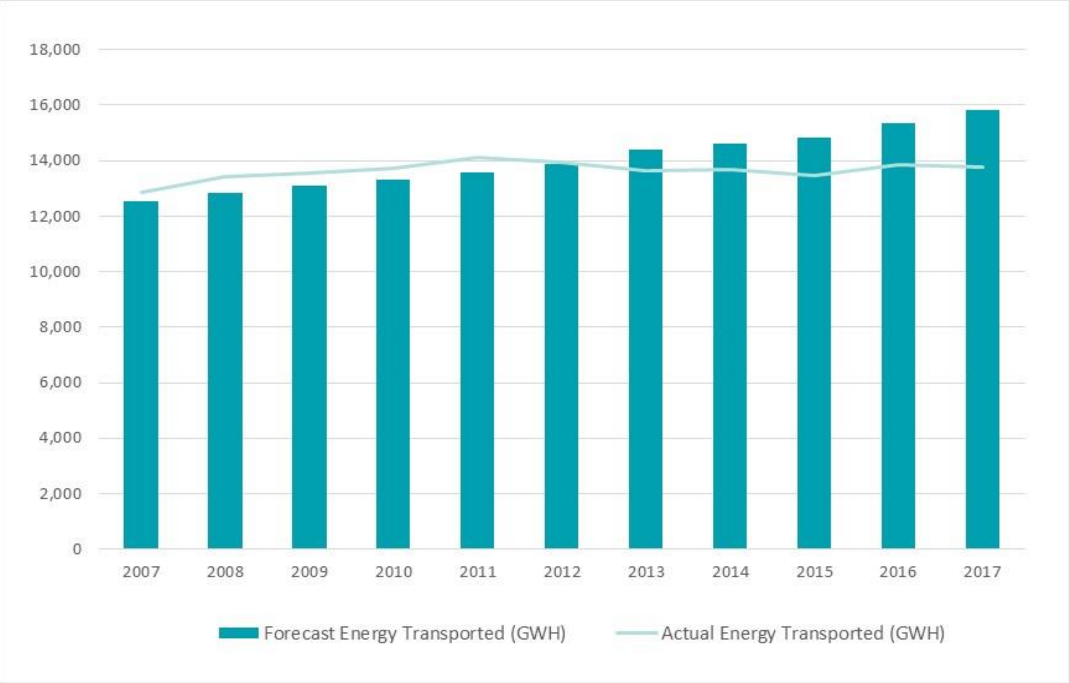


Figure 7 Comparison of Western Power access arrangement demand forecasts with actual demand for distribution



251. The 2017 Probability of Exceedance 10% (POE 10) forecast peak demand for 2017/18 was 3,991 MW and the Probability of Exceedance 50% (POE 50) forecast peak demand was 3,849 MW. The highest peak demand reported so far, for the 2017/18 year, occurred on 13 March 2018 at 17:25, and reached 3,558 MW.

252. In the draft decision, the ERA noted that while Western Power had developed a comprehensive approach to demand forecasting (including commissioning a third party review to test whether the method, process and assumptions it had used were

reasonable, robust and fit for purpose), there was insufficient information published with Western Power's proposal to enable stakeholders to fully evaluate the demand forecasts.

253. Western Power agreed to make more information publicly available and gave permission for its Connections Energy and Demand Forecast Methodology to be published on the ERA's website on 2 May 2018.

254. As identified by stakeholders, falling demand increases the risk of existing assets becoming under-utilised, which suggests a more cautious approach is needed to determine future expenditure requirements. In addition, falling demand without a corresponding fall in costs will put pressure on bills.

255. Western Power's revised proposal is based on the 2017 demand forecast provided with its initial proposal. In its draft decision, the ERA found that Western Power had developed a comprehensive approach to demand forecasting.

256. AEMO published its 2018 Electricity Statement of Opportunities in June 2018. As noted in the draft decision, AEMO's 2017 demand forecast was higher than Western Power's. Although AEMO has revised its forecast downwards it is still projecting increases in peak demand and consumption:

- The 10% Probability Of Exceedance (POE) peak demand will increase at an average rate of 0.4 per cent over the next five years and 0.6 per cent over the 10 year period.
- Consumption will increase by 0.5 per cent per annum over the next five years and 0.9 per cent per annum over the 10 year period.

257. Although AEMO is still forecasting increases in demand, in contrast to Western Power's forecast declines, the gap between the two forecasts has reduced.

258. Western Power has not advised the ERA of any change in its demand outlook. The ERA considers that Western Power's 2017 forecast is a reasonable estimate on which to base AA4.

Forecast operating expenditure

Access Code requirements

259. Section 6.40 of the Access Code provides for approved total costs and target revenue to include an amount for forecast non-capital costs (operating costs or OPEX) for the access arrangement period.

> 6.40 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.

260. "Efficiently minimising costs" is defined in the Access Code as meaning:

> 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.

261. "Good electricity industry practice" is defined in the Access Code to mean:

> the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances, consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines.

262. Sections 6.41 and 6.42 of the Access Code provide for the non-capital costs component of approved total costs to include non-capital costs incurred for an "alternative option" for providing covered services, subject to certain conditions being met. An alternative option is an activity undertaken by Western Power for the purpose of providing a covered service as an alternative to investing in a major augmentation of the network, and may include such activities as demand-side management or generation either instead of, or in addition to, network augmentation.

> 6.41 Where, in order to maximise the net benefit after considering alternative options, a service provider pursues an alternative option in order to provide covered services, the non-capital costs component of approved total costs for a covered network may include non-capital costs incurred in relation to the alternative option ("alternative option non-capital costs") if:
>
> (a) the alternative option non-capital costs do not exceed the amount of alternative option non-capital costs that would be incurred by a service provider efficiently minimising costs; and
>
> (b) at least one of the following conditions is satisfied:
>
> (i) the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or
>
> (ii) the alternative option provides a net benefit in the covered network over a reasonable period of time that justifies higher reference tariffs; or
>
> (iii) the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.
>
> 6.42 For the purposes of section 6.41(b)(i) "additional revenue" for an alternative option means:
>
> (a) the present value (calculated at the rate of return over a reasonable period) of the increased tariff income reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where "increased sale of covered services" means sale of covered services which would not have occurred had the alternative option not been undertaken); minus
>
> (b) the present value (calculated at the rate of return over the same period) of the best reasonable forecast of the increase in non-capital costs (other than alternative option non-capital costs) directly attributable to the increased sale of the covered services (being the covered services referred to in the expression "increased sale of covered services" in section 6.42(a)),
>
> where the "rate of return" is a rate of return determined by the Authority in accordance with the Code objective and in a manner consistent with this Chapter 6, which may be the rate of return most recently approved by the Authority for use in the price control for the covered network under this Chapter 6.

Western Power's initial proposal

263. Western Power's initial proposed operating expenditure for AA4 is set out in Table 31 below and totalled $1,805.1 million (which is $695 million less than the operating expenditure approved for AA3).

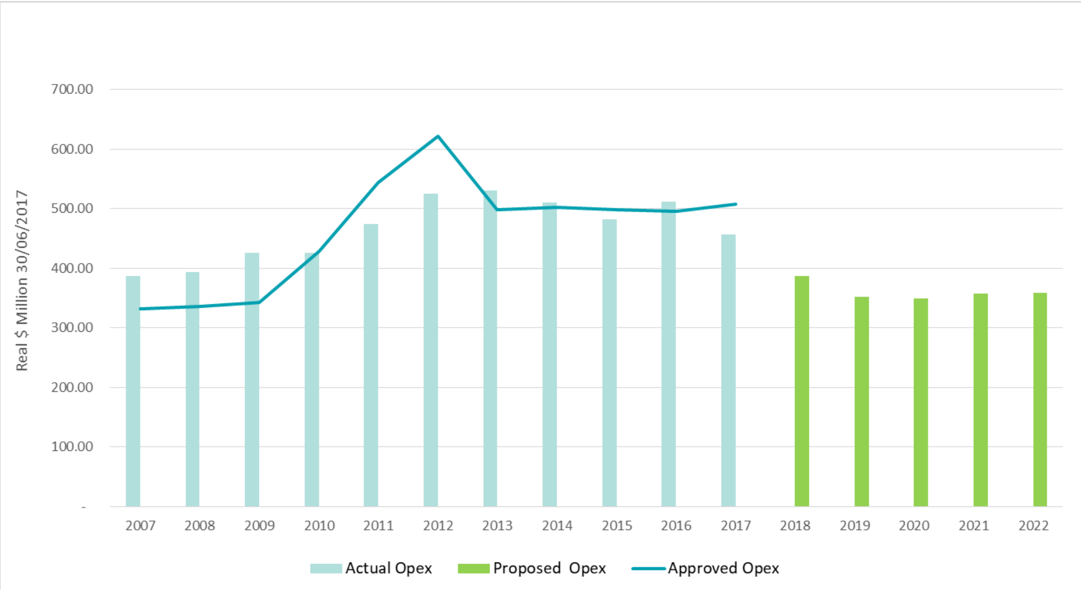
264. Figure 8 below compares Western Power's proposed operating expenditure for AA4 with actual and approved expenditures since the network became regulated in 2007.

265. Specific details of Western Power's forecast operating costs were incorporated into the ERA's considerations for its draft decision.

Table 31 Western Power AA4 proposed operating expenditure ($ million real June 2017)

	2016/17 Actual	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission	60.3	63.0	61.7	60.8	62.2	61.9
Corporate	41.3	30.8	22.5	22.4	22.4	22.7
Total transmission	**101.6**	**93.8**	**84.2**	**83.2**	**84.6**	**84.6**
Distribution	224.9	208.0	206.7	205.4	211.3	212.9
Corporate	113.0	84.5	61.6	61.1	61.3	61.9
Total distribution	**337.9**	**292.5**	**268.3**	**266.5**	**272.6**	**274.8**
Total operating expenditure	**439.5**	**386.4**	**352.5**	**349.7**	**357.2**	**359.3**

Figure 8 Western Power actual and proposed operating expenditure ($ million real June 2017)



Submissions on Western Power's proposal

266. Submissions on Western Power's forecast operating costs were incorporated into the ERA's considerations for its draft decision where applicable.

Draft decision

267. Under section 6.40 of the Access Code, the ERA must be satisfied that Western Power's forecast operating costs for AA4 include only those costs that would be incurred by a service provider efficiently minimising costs.

268. Western Power stated that it had used the "base-step-trend" method to forecast its operating expenditure. It used the final year of AA3 (i.e. 2016/17) to establish what it considered to be its efficient recurrent base operating expenditure. Western Power then forecast discrete step changes and changes in output and cost input trends over the period to forecast operating expenditure for each year of AA4. A summary of this process is provided in Table 32 below.

Table 32 Western Power AA4 proposed operating expenditure ($ million real June 2017)

Expenditure	2016/17 Actual[48]	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Recurrent network base costs	317.6	317.6	317.6	317.6	317.6	317.6	**1,588.0**
Step changes	-	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	**(25.0)**
Total recurrent network costs	**-**	**312.6**	**312.6**	**312.6**	**312.6**	**312.6**	**1,563.0**
Network growth escalation	-	2.9	5.9	9.4	12.6	15.7	**46.6**
Efficiency	-	(3.2)	(6.3)	(9.6)	(12.8)	(16.1)	**(48.0)**
Non-recurrent network costs	64.5[49]	32.5	1.2	0.2	0.0	0.5	**34.4**
Expensed indirect network costs	57.4	40.0	36.8	33.3	39.4	39.5	**189.0**
Labour cost escalation	-	1.4	2.4	3.7	5.4	7.1	**20.0**
Total	**439.5**	**386.4**	**352.5**	**349.7**	**357.2**	**359.3**	**1,805.1**

269. In considering Western Power's forecast of operating expenditure, the ERA assessed:

- the extent to which Western Power's proposed recurrent network base costs would be incurred by a service provider efficiently minimising costs, consistent with the requirements of section 6.40 of the Access Code; and
- whether Western Power had provided adequate justification that forecast trends and step changes in the level of costs over AA4 were consistent with those that would be incurred by a service provider efficiently minimising costs.

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48 Excluding non-revenue cap operating costs of $17 million.

49 Comprising $56 million for business transformation, $15 million for electricity market review costs and a $6 million credit for the write-back of a provision for the Mid-West energy project.

270. The ERA also considered advice provided by its technical consultant (GHD) on the efficiency of Western Power's proposed operating expenditure, which included a benchmarking exercise using the AER's benchmarking models and data from the network service providers operating in the national electricity market.

Recurrent network base costs

271. The ERA considered whether the actual operating costs for AA3 were consistent with a service provider efficiently minimising costs, and therefore, could constitute a relevant cost base against which forecasts of non-capital costs for AA4 could be assessed. The ERA assessed the efficiency of Western Power's base year (2016/17) operating expenditure by:

- verifying records of actual operating expenditure for AA3;
- reviewing the incentives for Western Power to minimise its operating expenditure;
- reviewing the base year operating expenditure line items (at a high level) for reasonableness; and
- benchmarking against the operating expenditure reported by other Australian network service providers.

Verification of operating costs for AA3

272. In accordance with the ERA's *Guidelines for Access Arrangement Information*, Western Power provided regulatory accounts that reconciled costs of regulated activities with a set of base accounts for the business. The reconciliation of claimed operating costs with recorded operating (non-capital) costs is shown in Table 33 below.

Table 33 Reconciliation of claimed operating expenditure for AA3 with recorded operating expenditure for Western Power ($ million real June 2017)

	Base account	Adjustments	Regulatory account	Claimed non-capital costs	AA3 forecast
Transmission					
Transmission 2012/13	123.2	4.6	127.8	127.8	114.7
Transmission 2013/14	118.5	3.8	122.3	122.3	113.8
Transmission 2014/15	116.7	3.8	120.5	120.5	114.2
Transmission 2015/16	123.0	3.5	126.5	126.5	116.5
Transmission 2016/17	102.8	2.8	105.6	105.6	119.3
Distribution					
Distribution 2012/13	394.0	9.1	403.1	403.1	384.1
Distribution 2013/14	380.5	7.7	388.2	388.2	387.9
Distribution 2014/15	353.0	8.4	361.4	361.4	383.5
Distribution 2015/16	376.8	8.5	385.3	385.3	378.5
Distribution 2016/17	344.0	7.1	351.1	351.1	388.4

273. The adjustments recorded for all years of AA3 are for fleet depreciation and were required to align Western Power's statutory accounting disclosures with its regulatory accounting disclosures. To achieve this, the unregulated fleet depreciation was disclosed as operating expenditure costs in the regulatory financial statements and not disclosed as depreciation and amortisation.

274. Western Power's regulatory accounts were audited for Western Power by the Office of the Auditor General. The ERA was satisfied that the regulatory accounts provided a true and correct indication of operating costs for AA3.

Incentives to minimise operating expenditure

275. Western Power's regulatory framework provides incentives for it to minimise its operating expenditure and achieve efficiencies greater than those in the access arrangement decision.

276. During an access arrangement period, Western Power keeps the benefit of any under expenditure compared with the level of expenditure forecast in the access arrangement decision. The gain sharing mechanism provides further opportunities for Western Power to retain the benefit of any under expenditure into the next access arrangement period. Providing Western Power meets all of its service standard benchmarks, the gain sharing mechanism ensures Western Power retains the benefit of any under expenditure for five years regardless of which year the under expenditure occurred.

277. These measures provided Western Power with an incentive to minimise its costs.

Analysis of base year network operating expenditure

278. Western Power used the operating expenditure for 2016/17 as the base year for its AA4 forecasts. Western Power stated that the actual level of expenditure in 2016/17 reflected the savings achieved through its business transformation program over the previous two years.

279. Western Power's actual operating expenditure for 2016/17, excluding non-revenue cap services, was $439.5 million. This is $60 million less than was forecast for AA3. Western Power made the following adjustments to its 2016/17 actual costs to establish its AA4 recurrent network base costs of $317.6 million:

- Removal of business transformation program costs of $56 million
- Removal of electricity market review costs of $15 million
- Reversal of the Mid-West energy project provision of $6 million
- Removal of indirect costs of $57 million

280. Western Power's recurrent network base costs break down was as follows:

- $182 million of operating expenditure for the distribution network
- $53 million of operating expenditure for the transmission network
- $83 million of corporate operating expenditure

281. A line-by-line review of operating expenditure, by regulatory category, was undertaken by GHD. The review showed that the actual costs for 2016/17 were lower, or in line with, the previous year's actual expenditure. It also showed that Western Power's forecasts for AA4 included further reductions.

282. An inconsistency was found between the Supervisory Control and Data Acquisition (**SCADA**) and communications operating expenditure and capital expenditure program. Western Power's proposed capital expenditure for AA4 included $52.7 million for transmission and $32.2 million for distribution to replace ageing SCADA assets. This should lead to lower maintenance requirements for newer assets. However, Western Power had proposed base operating expenditure similar to actual expenditure during AA3.

283. In view of this capital expenditure, the proposed operating expenditure should be reduced by 50 per cent as the asset replacement program will replace at least 50 per cent of the existing SCADA and communication asset base. Consequently, as set out in Table 34 below, the ERA required base operating expenditure to be reduced by $4.1 million for transmission, and $2.1 million for distribution, per annum to ensure forecast expenditure was at the level that would be incurred by a service provider efficiently minimising costs.

Table 34 ERA draft decision recurrent network base costs ($ million real June 2017)

Expenditure	2016/17 Actual[50]	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Proposed recurrent network base costs	317.6	317.6	317.6	317.6	317.6	317.6	**1,588.0**
Transmission SCADA	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	(4.1)	**(20.5)**
Distribution SCADA	(2.1)	(2.1)	(2.1)	(2.1)	(2.1)	(2.1)	**(10.5)**
Draft decision	**311.3**	**311.3**	**311.3**	**311.3**	**311.3**	**311.3**	**1,556.5**

Benchmarking analysis

284. As indicated, the ERA's technical consultant (GHD) benchmarked Western Power's 2016/17 operating expenditure against other Australian service providers' costs using the AER's benchmarking methods and data. Details of the benchmarking study was provided in section 7 of GHD's technical report to the ERA.[51] The main conclusions were:

- Depending on which model was used, Western Power ranked ninth or tenth (out of 14) for distribution service providers and sixth (out of six) for transmission service providers.
- As a combined electricity network, Western Power ranked last out of six.
- The comparable networks were SA Power Networks (distribution) and ElectraNet (transmission).
- Based on the benchmarking rankings for Western Power, the efficient range for total annual operating expenditure compared to a hypothetical combined SA Power Networks/ElectraNet electricity entity was between $368 million and $379 million.

285. Western Power's actual costs for 2016/17 of $439.5 million were $60.5 million higher than the top of the range indicated by the benchmarking study. However, 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) was below the predicted efficient cost.

286. While the benchmarking results were limited by the quality and standardisation of data and method used, it provided evidence that Western Power's proposed base expenditure for AA4 was at a level that would be incurred by a service provider efficiently minimising its costs.

[50] Excluding non-revenue cap operating costs of $17 million.

[51] GHD, *Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22*, p. 70 to 96, 26 April 2018

Forecast changes in operating expenditure during AA4

287. Western Power's forecast changes in operating expenditure over the AA4 period were considered in the following order:

- Step changes
- Network growth escalation
- Efficiency
- Non-recurrent network costs
- Indirect costs
- Labour cost escalation

Step changes

288. Western Power proposed a $5 million annual step change reduction for efficiencies from its business transformation program during AA3 that did not begin until the first year of the AA4 period. These efficiencies included:

- an update to the vegetation management strategy through a risk-based approach and the use of different practices from those currently used; and
- a reduction to unplanned overtime through improved systems and processes governing approval of overtime when responding to network faults.

289. In its review of metering capital expenditure, GHD identified that Western Power had over-estimated the number of replacement meters for non-compliant meters that were required for AA4. Consequently, metering operating expenditure was to be reduced to reflect a more accurate forecast of the number of replacement meters required.

290. The proposed step change reduction was to be reduced by a further $2.2 million per annum to ensure forecast expenditure is at the level that would be incurred by a service provider efficiently minimising costs (see Table 35 below).

Table 35 ERA draft decision step changes ($ million real June 2017)

Expenditure	2016/17 Actual[52]	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Proposed step changes	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	**(25.0)**
Metering	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	(2.2)	**(11.0)**
Draft decision	**(7.2)**	**(7.2)**	**(7.2)**	**(7.2)**	**(7.2)**	**(7.2)**	**(36.0)**

Network growth escalation

291. Western Power proposed that its recurrent operating expenditure forecasts for AA4 be adjusted for a forecast growth in the customer base and the physical size of the transmission and distribution networks. For the AA4 period, Western Power expects

[52] Excluding non-revenue cap operating costs of $17 million.

minimal overall network growth despite flat forecast peak demand, but it identified pockets of growth in some areas, which will drive its transmission network investment over the next 10 years.

292. Western Power's proposed scale escalation factors for AA4 are set out in Table 36 below.

Table 36 Western Power proposed scale escalation factors for AA4

Expenditure	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22
Distribution						
Customer numbers	67.6%	1.65%	1.73%	1.69%	1.66%	1.63%
Circuit length	10.7%	0.91%	0.91%	0.91%	0.91%	0.91%
Annual average growth in highest maximum demand	21.7%	0%	0%	0%	0%	0%
Distribution growth	**100%**	**1.21%**	**1.26%**	**1.24%**	**1.22%**	**1.20%**
Transmission						
Circuit length	28.7%	0.32%	0.33%	0.22%	0.33%	0.32%
Annual average growth in highest maximum demand	22.1%	0%	0%	0%	0%	0%
Energy volumes delivered	21.4%	0.3%	0%	2.89%	2.5%	0.0%
Annual average growth in entry and exit points	27.8%	-0.24%	-0.7%	-0.25%	-0.98%	0.00%
Transmission growth	**100%**	**0.09%**	**-0.11%**	**0.62%**	**0.35%**	**0.09%**

293. Western Power also applied growth escalation to corporate costs. 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 was to be applied to corporate costs.

294. The variables proposed by Western Power were consistent with those used by the AER. However, the AER updated the weightings for each variable based on more recent benchmarking analysis. The ERA considered that if the AER network growth escalation method was to be used, it had to reflect the most recent data from the AER, including the current weightings used by the AER.[53, 54] Updating the weightings

[53] Economic Insights, Position Paper for Review of TNSP Economic Benchmarking, 9 August 2017, p. 31.

[54] Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report, 31 October 2017, section 1.1, p. 1.

to be consistent with the most recent data from the AER would result in growth escalation as set out in Table 37.

Table 37 Western Power proposed scale escalation factors adjusted for AER revised weightings

Expenditure	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22
Distribution						
Customer numbers	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%
Annual average growth in highest maximum demand	30.4%	0%	0%	0%	0%	0%
Distribution growth	**100%**	**0.97%**	**1.01%**	**0.99%**	**0.98%**	**0.97%**
Transmission						
Circuit length	38.0%	0.32%	0.33%	0.22%	0.33%	0.32%
Annual average growth in highest maximum demand	19.0%	0%	0%	0%	0%	0%
Energy volumes delivered	23.0%	0.3%	0%	2.89%	2.5%	0.0%
Annual average growth in entry and exit points	20.0%	-0.24%	-0.7%	-0.25%	-0.98%	0.00%
Transmission growth	100%	0.14%	-0.2%	0.7%	0.5%	0.12%

295. The ERA reviewed Western Power's forecasts for each of the variables and noted the circuit length estimates were based on AA3 actuals. Given Western Power was forecasting reductions in its demand forecasts for AA4, the ERA considered that the circuit length forecasts should also be updated for AA4.

296. The transmission energy volumes delivered appeared to only include volumes delivered to transmission connected customers. Total energy volumes transported through the transmission system should be used, which are forecast to decline each year, rather than increase as Western Power assumed for 2017/18, 2019/20 and 2020/21. This would result in transmission scale escalation being zero or negative.

297. The ERA was also not convinced that the distribution cost escalation attributed to an increase in customer numbers was accurate and consistent with a service provider efficiently minimising its costs. The proposed scale escalation resulted in $75.00 of recurring operating expenditure being added for each new customer. The ERA considered that it would need evidence to support such a cost increase before approving any customer growth scale escalation.

298. For the purpose of the draft decision, the ERA removed scale escalation on the basis that it was inconsistent with the costs that would be incurred by a service provider efficiently minimising costs.

Efficiency

299. Western Power included a one per cent per annum productivity improvement in its proposed operating costs. Western Power stated that this was based on anticipated savings during AA4 due to efficiencies achieved through business improvement initiatives and programs during AA3.

300. Western Power's proposed operating expenditure for AA4 included efficiencies achieved during AA3 that were higher than assumed in the AA3 decision, and included further step reductions in AA4. The total base operating expenditure, including indirect costs, is less than the predicted efficient cost using the AER's benchmarking models. On this basis, a proposed one per cent annual reduction was considered reasonable.

301. However, the proposed capital program for AA4 included $184 million expenditure for depot modernisation. Western Power stated this program would deliver recurring expenditure savings of $10 million per annum and a one-off benefit of $60 million. The capital program also included $149 million for new business driven information technology systems, which would deliver further efficiencies. These efficiencies did not appear to have been taken into account in Western Power's proposed one per cent productivity improvement.

302. The ERA has further considered Western Power's proposed one per cent productivity improvement in this final decision. For the purpose of the draft decision, the ERA assumed the proposed one per cent annual reduction was consistent with what would be achieved by a service provider efficiently minimising costs.

Non-recurrent network operating expenditure

303. Western Power's forecast non-recurrent operating expenditure was $34.4 million for AA4. The expenditure was for corporate costs and consisted of:

- the business transformation program ($28.3 million);
- the electricity market review program ($5.1 million); and
- ERA regulatory costs ($1.0 million).

304. The business transformation program is due to be completed in 2018. Western Power noted that to date it had realised $72 million of operating efficiencies in the AA3 period and had removed a further $5 million from the base year to reflect what it considered an efficient amount of operating expenditure. It also noted that the program had resulted in $51 million of indirect cost efficiencies in the AA3 period and the indirect costs will be further reduced by $12 million per year for AA4.

305. Western Power stated that the success of its business transformation program relied on the completion of several critical initiatives, which included:

- restructuring areas of the business;
- standardising depot and crew tasks;
- enhancing forecasting processes;

- an automated planned outage notification system for network outages; and
- a “self-service portal HR solutions centre”.

306. While Western Power had identified the above initiatives as being completed with non-recurrent expenditure, it was not clear how any savings from the final elements of the business transformation program during 2017/18 were incorporated in Western Power’s forecast operating expenditure. On that basis, the $28.3 million was to be excluded as it was not consistent with a service provider efficiently minimising costs.

307. Western Power included $5.1 million under the heading “electricity market review costs”. It stated that these costs were required for the relocation of staff from East Perth to AEMO’s control centre, and the transfer of systems to AEMO following the transfer of system management functions from Western Power to AEMO.[55]

308. Prior to 1 July 2016, a ring-fenced business unit in Western Power was responsible for providing system management services to the Wholesale Electricity Market (WEM). The costs of this function were recovered from WEM participants and not included in Western Power’s access arrangement target revenue. On 1 July 2016, AEMO became legally responsible for system management functions. Between July 2016 and October 2016, AEMO and Western Power entered into an operating agreement for Western Power to exercise system management functions on AEMO’s behalf. On 31 October 2016, AEMO became responsible for system management functions and had a services agreement with Western Power to provide access to Western Power’s control centre and equipment, as well as a secondee service. This agreement continued until AEMO completed its new control centre in the Perth CBD.

309. 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 was unclear why Western Power was 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, system management costs did not form part of the provision of network covered services and therefore should not be included in Western Power’s AA4 forecast operating expenditure.

310. Western Power included non-recurring costs of $0.5 million in 2017/18 and 2021/22 for the ERA costs that it is required to pay under the *Economic Regulation Authority (Electricity Networks Access Funding) Regulations 2012*[56] related to the AA4 and AA5 review processes.

311. Western Power stated that the costs included in its AA3 expenditure did not take into account the additional costs incurred during an access arrangement review because the regulations took effect after the AA3 review was completed. The inclusion of these costs was consistent with a service provider efficiently minimising costs.

[55] Western Power Access Arrangement Information, p. 138.

[56] These regulations were introduced on 10 October 2012 and require Western Power to pay for the ERA’s costs for its electricity access functions.

312. For the reasons set out above, the ERA did not consider Western Power's proposed non-recurrent network costs were consistent with a service provider efficiently minimising costs. It required the costs to be amended as in Table 38 below.

Table 38 ERA draft decision non-recurrent network costs ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Proposed non-recurrent network costs	32.5	1.2	0.2	0.0	0.5	34.4
Business transformation program	(28.3)	-	-	-	-	(28.3)
Electricity market review program	(3.7)	(1.2)	(0.2)	-	-	(5.1)
Draft decision	**0.5**	**0.0**	**0.0**	**0.0**	**0.5**	**1.0**

Indirect costs

313. Indirect costs are costs that are not directly linked to the networks program but are incurred as a result of the works program. The costs cover project management and coordination, as well as maintaining computers and facilities for operational staff. Indirect costs are allocated to activities and expensed or capitalised in line with Western Power's cost and revenue allocation model.

314. Western Power's proposed indirect expenditure for AA4 is set out in Table 39 below. Western Power's recurrent network base costs were based on actual indirect costs (excluding those attributable to non-revenue cap expenditure) incurred in 2016/17.

Table 39 Western Power AA4 proposed indirect expenditure ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Recurrent network base costs	181.4	181.4	181.4	181.4	181.4	907.1
Step changes	(12.0)	(12.0)	(22.5)	(22.5)	(22.5)	(91.5)
Total recurrent indirect costs	**169.4**	**169.4**	**158.9**	**158.9**	**158.9**	**815.6**
Network growth escalation	1.6	3.2	4.7	6.4	7.9	23.7
Efficiency	(1.7)	(3.4)	(4.9)	(6.5)	(8.2)	(24.7)
Labour cost escalation	0.6	1.2	1.7	2.4	3.2	9.1
Total indirect costs	**169.9**	**170.3**	**160.5**	**161.2**	**161.8**	**823.7**

315. The indirect costs were allocated across capital and operating expenditure based on Western Power's cost and revenue allocation model. Western Power's proposed allocation is set out in Table 40 below.

Table 40 Western Power AA4 proposed indirect expenditure allocation ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Total indirect costs	**169.9**	**170.3**	**160.5**	**161.2**	**161.8**	**823.7**
Capitalised						
Transmission	29.8	35.2	36.5	38.1	36.8	176.4
Distribution	99.9	98.1	90.3	83.2	84.8	456.3
Total	129.7	133.3	126.8	121.3	121.6	632.7
Operating expenditure						
Transmission	10.0	9.1	8.2	9.7	9.7	46.7
Distribution	30.2	27.9	25.4	30.3	30.6	144.4
Total	40.2	37.0	33.6	40.0	40.3	191.1

316. Western Power stated that its step change reduction of $12 million was for productivity gains and reductions through a combination of system enhancements and process improvements in asset management, asset operations, finance and customer and corporate services.

317. The step change increased by $10.5 million in the last three years of AA4 and reflected a change Western Power was proposing to make to fleet expenditure. As discussed under *forecast capital expenditure*, Western Power proposed to capitalise fleet costs. For reasons set out in the forecast capital expenditure section of the draft decision, the ERA did not accept this. Consequently, fleet costs were to remain in indirect costs, and the step change was to be $12 million for each year of AA4.

318. Western Power applied network growth to indirect costs. However, similar to corporate costs, indirect costs (such as project management and coordination, and maintaining computers and facilities for operational staff) are not proportional to growth in service outputs that may result from changes in customer demand. Consequently, no growth escalation were to be applied to indirect costs.

319. Consistent with its proposed operating expenditure, Western Power included a one per cent per annum productivity improvement (negative adjustment) in its proposed indirect costs. The ERA stated that it would further consider the level of efficiencies in its final decision to ensure the efficiencies arising from the depot rationalisation and new business driven IT systems are taken account of.

320. The ERA did not consider Western Power's proposed indirect costs were consistent with a service provider efficiently minimising costs. It required the costs to be amended as in Table 41 and Table 42 below.

Table 41 ERA draft decision indirect expenditure ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Recurrent network base costs	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 indirect costs	**169.4**	**169.4**	**169.4**	**169.4**	**169.4**	**847.1**
Network growth escalation	-	-	-	-	-	-
Efficiency	(1.7)	(3.4)	(5.0)	(6.7)	(8.3)	(25.1)
Labour cost escalation	0.6	1.1	1.8	2.5	3.2	9.3
Total indirect costs	**168.3**	**167.2**	**166.2**	**165.2**	**164.4**	**831.3**

Table 42 ERA draft decision indirect expenditure allocation ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Total indirect costs	168.3	167.2	166.2	165.2	164.4	831.3
Capitalised						
Transmission	23.9	29.2	30.5	29.0	27.0	139.6
Distribution	102.5	100.1	99.6	92.9	94.3	489.4
Total	126.4	129.3	130.1	121.9	121.3	629.0
Operating expenditure						
Transmission	9.9	9.0	8.6	10.2	10.2	47.9
Distribution	32.0	28.9	27.5	33.1	32.8	154.4
Total	42.0	37.9	36.1	43.3	43.0	202.3

Labour cost escalation

321. Western Power incorporated into both its proposed operating expenditure and capital expenditure forecasts, movements in the cost of labour that would escalate at a rate above CPI. Including a labour cost escalation factor was consistent with ensuring operating expenditure only includes those costs that would be incurred by a service provider efficiently minimising costs, providing the escalation factor was based on a reasonable forecast.

322. Western Power commissioned Synergies Economic Consulting (Synergies) to forecast a Wage Price Index (WPI) for the Electricity, Gas, Water and Waste Services sector (EGWWS) and CPI that would be used in its AA4 proposal.

323. Synergies used a whole-of-economy model to develop economic forecasts for Western Australia and Australia. These economic forecasts were then used as inputs into an econometric model, which quantified the relationship between CPI and WPI in the EGWWS industry and their key economic drivers. Synergies' forecasts

are set out in Table 43 below, together with the latest Western Australian Treasury forecast of WPI.

Table 43 Synergies' forecast labour escalation rates for AA4

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	Average
CPI	2.0	2.5	2.5	2.5	2.5	2.4
Nominal WPI-All Industries Western Australia	2.4	2.8	3.0	3.1	3.1	2.9
WA Treasury WPI forecast	1.5	1.75	2.75	3.0	-	-
Nominal WPI-EGWWS Western Australia	2.9	3.3	3.5	3.6	3.7	3.4
Real WPI-EGWWS Western Australia	0.9	0.8	1.0	1.1	1.2	1.0

324. As seen in the table (above), Synergies' forecast of WPI was higher than the Western Australian Treasury forecasts for the first few years of AA4. While the Synergies report was not dated, it would have been prepared before October 2017, hence it did not reflect current data.

325. As the labour cost escalation is a relatively small component of Western Power's proposed costs ($20 million of total operating expenditure of $1.8 billion and $9.3 million of total indirect costs of $831.3 million) and there is still some uncertainty about other elements of Western Power's proposed operating costs, the ERA did not amend the labour escalation component for the purpose of its draft decision. The ERA required Western Power to update its forecasts to reflect current data so that it could review the forecast for its final decision.

Total operating expenditure

326. Taking into account the considerations of the individual cost line items set out above, network growth escalation, labour cost escalation and other adjustments, Western Power's forecast of operating expenditure (as set out in its access arrangement information) was not consistent with the requirements of section 6.40 of the Access Code. The ERA set out its draft decision operating expenditure forecasts as in Table 44 below.

Table 44 ERA draft decision operating expenditure ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Recurrent network base costs	311.3	311.3	311.3	311.3	311.3	1,556.5
Step changes	-7.2	-7.2	-7.2	-7.2	-7.2	-36.0
Total recurrent network costs	**304.1**	**304.1**	**304.1**	**304.1**	**304.1**	**1,520.5**
Network growth escalation	0.0	0.0	0.0	0.0	0.0	0.0
Efficiency	-3.0	-6.1	-9.0	-12.0	-14.9	-45.0
Non-recurrent network costs	0.5	0.0	0.0	0.0	0.5	1.0
Expensed indirect network 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
Total	**344.6**	**337.9**	**334.4**	**339.8**	**338.6**	**1,695.4**

327. The ERA required amendments to the target revenue and price control in Western Power's proposed access arrangement to be consistent with the operating cost forecasts shown in Table 45 below.

Draft Decision Required Amendment 5

The proposed access arrangement must be amended to reflect the forecast operating expenditure set out in Table 45.

Table 45 ERA draft decision operating expenditure by service ($ million real June 2017)

	2016/17 Actual	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission	60.3	58.7	57.4	56.7	58.2	57.9
Corporate	41.3	22.1	21.8	21.7	21.5	21.6
Total transmission	**105.6**	**80.8**	**79.2**	**78.4**	**79.7**	**79.4**
Distribution	224.9	203.4	199.1	196.6	201.2	200.1
Corporate	113.0	60.4	59.7	59.3	59.0	59.0
Total distribution	**351.1**	**263.8**	**258.6**	**255.9**	**260.1**	**259.1**
Total operating expenditure	**439.5**	**344.6**	**337.8**	**334.3**	**339.8**	**338.5**

Western Power's revised proposal

328. Western Power has not accepted the ERA's draft decision required amendment to amend forecast operating expenditure for the AA4 period to the amounts set out above in Table 45.

329. Western Power's reasons for not accepting the ERA's draft decision amendment are set out below.

Base Year operating expenditure

330. In the draft decision, the ERA reduced Western Power's base year for SCADA and communications for both transmission and distribution by a total of $31 million over the AA4 period. This was due to Western Power proposing significant capital expenditure in these areas to replace ageing assets which should lead to lower maintenance costs in future.

331. Western Power noted that in the draft decision the ERA and GHD concluded that Western Power's proposed base year operating expenditure was at a level that would be incurred by a service provider efficiently minimising costs and thereby meeting section 6.40 of the Access Code and the Access Code objective.

332. Western Power noted the reduction of $6.3 million to the base year and $31 million in total over the AA4 period, is based on advice from GHD who conducted a line-by-line (bottom-up) assessment.

333. Western Power states that this type of bottom-up assessment is incompatible with a top-down forecasting approach and it is not appropriate to make regulatory category level adjustments to an expenditure forecast that has not been developed using a bottom-up approach.

334. As a result Western Power has not accepted the ERA's proposed base year reduction.

335. Western Power has made two changes to the efficient base year from its initial proposal to correct an allocation error it made when analysing its 2016/17 operating expenditure.

336. The first change, which was identified in its revised proposal, increases the base year by $2.4 million for costs that were allocated to the Electricity Market Review as non-recurrent costs but have since been deemed as recurrent costs.

337. The second change, notified to the ERA in response to an information request, increases the base year by $2.1 million for costs that were allocated to the business transformation project as non-recurrent but have been since been deemed as recurrent costs.

Step Changes

338. Western Power has not accepted the ERA's draft decision step change of $2.2 million per annum for metering expenditure. Western Power notes that the AA4 proposal was based on installing 355,493 new and replacement meters and in the draft decision the ERA amended this forecast to 373,493.

339. Western Power notes that in the draft decision at footnote 50, subsequent advice from GHD led the ERA to amend its forecast metering volumes to 331,925 and that, similar to the base year reduction proposed by the ERA, this is another example of a bottom-up reduction for specific activities which is inconsistent with Western Power's forecasting method.

Network Growth Escalation

340. In the draft decision, the ERA removed network growth escalation on the basis there was insufficient evidence to demonstrate the proposed increases were consistent with the costs that would be incurred by a service provider efficiently minimising costs.

341. Western Power states it has used the Economic Insights approach to escalate its base year separately for the transmission and distribution businesses. Western Power notes that this approach is designed to accurately reflect changes in the size of the network so that escalation can be factored into network business' forecast operating expenditure and that this approach is routinely adopted by the AER.

342. Western Power has stated that it considers the application of Economic Insights' method in its entirety, including applying scaling factors to corporate operating expenditure and expensed indirect costs, is necessary to deliver an operating expenditure allowance consistent with section 6.40 of the Access Code.

Non-recurrent network costs

343. Western Power has not accepted the ERA's draft decision to remove EMR and BTP non-recurrent forecast expenditure. Western Power has included the BTP expenditure of $28.3 million that it initially proposed in full and has reduced the EMR expenditure from $5.1 million down to $4.0 million in this revised proposal.

344. Western Power notes it has incurred $14 million to separate system management functions from network operations and that approximately 80 per cent of that has been charged to AEMO under its service level agreement.

345. Western Power notes that the remaining costs are required to enable the network operation function to operate independently as part of the covered network and that it will continue to incur costs associated with the transition over the AA4 period primarily for the remediation of ICT systems to finalise the disaggregation.

346. Western Power also states that it and the AEMO have agreed the apportionment of costs to each party and formally documents these in a services agreement and the two parties have made their own assessment of the total costs and the proportion that should be recovered from the wholesale market participants and Western Power's customers.

347. As noted above, Western Power has reduced the initial proposal EMR expenditure by $1.1 million. This is as a result of removing costs associated with internal staff that were included in the base year as well as in these non-recurrent costs.

348. Western Power has again included $28.3 million to complete the business transformation program that was in its initial proposal but was rejected in the ERA's draft decision.

349. Western Power states in its revised proposal that should the ERA require it to remove the $28 million of costs associated with the completion of the BTP, it would be unable to deliver the $158 million of efficiencies forecast in AA4, and would need to reverse the associated contingent adjustments.

350. Western Power also states that the efficiencies gained from the BTP as a complete program more than outweigh the $28 million cost of completion and considers that a service provider efficiently minimising costs would complete this program given the potential benefits to customers.

Indirect Costs

351. Western Power has accepted the ERA's draft decision amendment to not capitalise fleet leases and retain the expenditure in the indirect cost section of operating expenditure. As a result, Western Power has removed the associated step change it initially proposed.

352. Western Power has retained the $12 million per annum step change for BTP initiatives and has also retained the one per cent efficiency dividend that the ERA accepted in the draft decision.

353. Western Power has included, as it did in its initial proposal, network escalation to indirect costs which the ERA removed in the draft decision.

Labour cost escalation

354. In its revised proposal Western Power has used updated values provided to it by its economic consultant, Synergies Economic Consulting. Synergies has calculated its own values for a Western Australian based EGWWS forecast which it used to determine wage price growth for Western Power.

355. Western Power has also updated the proportion of labour to which labour cost escalation will apply in its forecasts. Western Power in its initial proposal used the historical average labour cost component to calculate the proportion of labour costs in relation to the total spend over the last two years which resulted in applying labour cost escalation to 40 per cent of total operating expenditure.

356. Western Power in its revised proposal now seeks to apply a method the AER has used in recent decisions and apply benchmark efficient labour cost proportions as opposed to actual labour cost component proportions.

357. Western Power seeks to apply labour cost proportions to distribution and transmission separately of 57.7 per cent for distribution and 70.4 per cent for transmission. For corporate expenditure Western Power has used a weighted average of the distribution and transmission labour cost proportions.

Further Submissions

358. The AEC considers the ERA needs to focus further on:

> Whether the proposed one percent per annum productivity improvement in operating costs is reasonable, specifically given the network operator does not appear to have adequately taken into account the operational efficiencies from proposed depot modernisations and technology system improvements.

Considerations of the ERA

359. Western Power initially forecast operating expenditure of $1,805.1 million for the fourth access arrangement period. The ERA did not approve Western Power's forecast and determined in the draft decision that $1,695.4 of forecast operating expenditure met the Access Code requirements for inclusion.

360. Western Power submitted a revised forecast operating expenditure for AA4 of $1,830.5 in its response to the ERA's draft decision.

361. The ERA has reviewed Western Power's submission and supporting documentation and does not accept its revised operating expenditure forecasts. Reasons for not accepting Western Power's proposed forecast expenditure and ERA determined forecasts are set out below.

Analysis of base year network operating expenditure

362. Western Power used the operating expenditure for 2016/17 as the base year for its AA4 forecasts. As discussed above, Western Power has increased its base year costs for expenditure in the 2016/17 year which formed part of the business transformation program and the electricity market review program that was initially treated as non-recurrent but has subsequently been identified as recurrent costs.

363. Western Power did not accept the ERA's Draft Decision determination of reducing SCADA and communications expenditure by $6.3 million from the base year costs. As a result Western Power's forecast base year cost in it revised proposal is $322.6 million.

364. The ERA notes that in Western Power's response to the draft decision, Western Power did not dispute the $6.3 million reduction to SCADA and communications on the basis that the amount was unreasonable or would not occur, only on the basis that the method used to determine the reduction was inconsistent with the determination of the overall base year costs.

365. Approving expenditure that would not be incurred by a service provider efficiently minimising costs is inconsistent with section 6.40 of the Access Code.

366. Consequently, as a result of the extensive capital expenditure program for SCADA and communications, the proposed operating expenditure should be reduced by 50 per cent. The ERA requires Western Power to reduce the base operating expenditure by $4.2 million for transmission and $2.1 million for distribution, per annum to ensure forecast expenditure is at the level that would be incurred by a service provider efficiently minimising costs.

367. The ERA accepts Western Power's increase to the base year for the correction to the allocation of costs between non-recurrent and recurrent.

368. The ERA's determination on recurrent network base costs is set out in Table 46 below.

Table 46 ERA final decision recurrent network base costs ($ million real June 2017)

Expenditure	2016/17 Actual[57]	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Proposed recurrent network base costs	322.6	322.6	322.6	322.6	322.6	322.6	**1,613.0**
Transmission SCADA	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	(4.2)	**(21.0)**
Distribution SCADA	(2.1)	(2.1)	(2.1)	(2.1)	(2.1)	(2.1)	**(10.5)**
Draft decision	**316.3**	**316.3**	**316.3**	**316.3**	**316.3**	**316.3**	**1,581.5**

Forecast changes in operating expenditure during AA4

369. Western Power's forecast changes in operating expenditure over the AA4 period were considered in the following order:

- Step changes
- Network growth escalation
- Efficiency
- Non-recurrent network costs
- Indirect costs
- Labour cost escalation

Step changes

370. Western Power has maintained the proposed $5 million annual step change reduction for efficiencies from its business transformation program that was not completed prior to the start of the AA4 period.

371. The ERA proposed in the draft decision an additional step change of $2.2 million for metering costs which was not accepted by Western Power. The ERA had reviewed additional advice from GHD and has determined to not include this metering reduction as a step change in the final decision.

372. In reviewing Western Power's revised proposed capital expenditure, GHD sought to identify any areas where proposed capital expenditure would have an impact on operating expenditure in the AA4 period.

373. GHD identified operating expenditure savings as part of the depot optimisation capital expenditure program Western Power is in the process of undertaking. GHD has noted that $10 million of savings per annum as identified by Western Power should be included separately and not be included as part of the 1 per cent efficiency reduction.

[57] Excluding non-revenue cap operating costs of $17 million.

374. GHD noted that savings that would eventuate from the depot optimisation program would not start until 2020/21 and accelerate in 2021/22 and has proposed staggered reductions accordingly.

375. The ERA has reviewed GHD's report and Western Power's submission. Based on the proposed depot optimisation program as outlined by Western Power and Western Power's statement that operating expenditure savings will result from the program, the ERA agrees with GHD's staggered introduction of the step change reduction.

376. As a result the step change will occur in the last two years of AA4 and will see a saving of $2.5 million in 2020/21, increasing by $5 million in 2021/22 up to a cumulative step change of $7.5 million in the last year of AA4.

377. The proposed step change reductions are set out in Table 47 below.

Table 47 ERA final decision step changes ($ million real June 2017)

Expenditure	2016/17 Actual	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Proposed step changes	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	(5.0)	**(25.0)**
Depot Optimisation	(0.0)	(0.0)	(0.0)	(0.0)	(2.5)	(7.5)	**(10.0)**
Draft decision	**(5.0)**	**(5.0)**	**(5.0)**	**(5.0)**	**(7.5)**	**(12.5)**	**(35.0)**

Network growth escalation

378. In the draft decision, the ERA removed scale escalation on the basis that it was inconsistent with the costs that would be incurred by a service provider efficiently minimising costs.

379. The ERA considered that if the AER network growth escalation method (data provided by Economic Insights) was to be used, it had to reflect the most recent data and current weightings. Western Power has updated its data and weightings in its response to the draft decision.

380. As noted above in the Western Power's revised proposal section, Western Power considers the application of Economic Insights' method in its entirety, including corporate operating expenditure and expensed indirect costs, as proposed in its revised proposed forecast is necessary to deliver an operating expenditure allowance consistent with section 6.40 of the Access Code.

381. The ERA has reviewed Western Power's proposal and accepts that while Western Power expects minimal overall network growth, with only pockets of growth in some areas, there should be an allowance for network growth included in the operating expenditure.

382. The ERA has determined that the inclusion of network growth in operating expenditure for AA4 will only apply to the transmission and distribution networks. The ERA maintains as was set out in the draft decision that network escalation should not apply to corporate costs.

383. 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.

Efficiency

384. Western Power has maintained the inclusion of a one per cent per annum productivity improvement in its proposed operating costs as it included in its initial proposal.

385. The ERA accepted this one per cent in the draft decision. The ERA noted in the draft decision that it would review the one per cent reduction in the final decision as it appeared that savings from Western Power's depot optimisation program had not been taken into account.

386. As the ERA has included in the final decision a step change reduction to take account of Western Power's savings from its depot optimisation program, the ERA accepts the one per cent productivity improvement efficiency dividend.

Non-recurrent network operating expenditure

387. Western Power has forecast non-recurrent operating expenditure of $33.3 million for the AA4 period. This is $1.1 million less than it forecast in its initial proposal but $32.3 million more than the ERA determined in the draft decision.

388. The $33.3 million of expenditure is forecast for corporate costs and consists of:

- The business transformation program ($28.3 million);
- The electricity market review program ($4.0 million); and
- ERA regulatory costs ($1.0 million).

389. As in the draft decision, the ERA accepts the $1.0 million of ERA regulatory costs but does not accept the business transformation or electricity market review program expenditure.

390. Western Power has included $4.0 million in costs arising from the electricity market review program. Western Power submits these costs were necessary following the transfer of system management functions to AEMO.

391. Prior to AEMO taking on these functions, Western Power had a ring-fenced business unit – System Management – which was responsible for managing the power system. The costs for this function were collected through market fees charged to the wholesale energy market participants.

392. The ERA has reviewed these costs and they appear to be associated with disentangling system management from Western Power. It is likely these costs would not have been incurred if the System Management business unit had been more effectively ring fenced from Western Power's network operator functions.

393. The ERA considers that any costs arising from the disentangling of system management from Western Power should be funded by the State Government as they arose due to the reforms implemented by the State Government.

394. Western Power has included business transformation program expenditure of $28.3 million in its revised proposal as it did in its initial proposal. Western Power

states it requires this non-recurrent expenditure to finish its BTP (Business Transformation Program) initiative.

395. Of the $28.3 million, $13.5 million is redundancy costs. The AER determined in its Essential Energy Final Decision for the period 2015-19, that for Essential Energy's network reform program, the restructure of its workplace was probably only needed because it was not currently operating as efficiently as it could. The AER determined that redundancy costs would not be included in an estimate of ongoing efficient and prudent operating expenditure.

396. The ERA has taken the same view with the redundancy costs included by Western Power as part of its Business Transformation Program reform project. Costs for redundancy payments do not form part of an efficient and prudent service provider's ongoing operating expenditure.

397. The remaining $14.8 million of expenditure, primarily payments to consultants, for the business transformation program relates to initiatives across many areas of the organisation. In the draft decision, the ERA excluded the BTP expenditure as it was not clear how any savings from the final elements of the program were incorporated in Western Power's forecast operating expenditure.

398. As set out in the draft decision, the $5 million step change in base costs included by Western Power for efficiencies not realised at the end of AA3 starts from the first year of AA4. Consequently, the efficiencies must have arisen from the business transformation program expenditure during AA3 and are not related to the business transformation program expenditure during the first year of AA4.

399. Western Power in its response to the draft decision has not provided any additional information to link these specific program initiatives to cost savings and reductions in its proposed operating expenditure.

400. Having considered this matter further, the ERA considers that, similar to redundancy costs, consultancy expenditure for the purpose of developing an efficiency program should not be included in the operating cost forecast for the access arrangement.

401. As identified in the benchmarking undertaken by GHD, Western Power performed poorly during AA3. The need for the business transformation program arose because Western Power was not operating efficiently. The ERA recognises the business transformation program has delivered significant savings and Western Power's proposed operating expenditure for AA4 is much lower than the AA3 expenditure. However, the benchmarking indicates this will bring Western Power in line with other efficient companies in the NEM. Consequently, the costs do not form part of an efficient and prudent service provider's expenditure as they have been incurred to reduce Western Power's costs to the level that would be incurred by an efficient and prudent service provider.

Indirect Costs

402. Western Power's revised proposed indirect expenditure for AA4 is shown in Table 48 below. Western Power's recurrent network base costs are based on actual indirect costs (excluding those attributable to non-revenue cap expenditure) incurred in 2016/17)

Table 48 Western Power AA4 revised proposed indirect expenditure ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Recurrent network base costs	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 indirect costs	**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	(1.7)	(3.4)	(5.1)	(6.7)	(8.4)	(25.3)
Labour cost escalation	0.4	1.7	3.3	5.0	6.6	17.0
Total indirect costs	**168.4**	**168.3**	**168.5**	**169.0**	**169.3**	**843.5**

403. Western Power has maintained the step change reduction of $12 million for improvements in productivity. In its initial proposal, Western Power included an additional step change reduction for the capitalising of fleet in the last three years of the AA4 period.

404. The ERA did not accept the capitalisation of fleet in the draft decision and accordingly removed the step change to indirect costs in the draft decision. Western Power has accepted this draft decision amendment and has maintained fleet costs in the indirect expenditure category.

405. The ERA has accepted in this final decision network escalation for the expensed portion of indirect costs as proposed by Western Power in its revised proposal and the one per cent efficiency reduction.

406. The ERA has also included labour cost escalation to indirect costs, however, using a different method than that proposed by Western Power which is explained in more detail in the following section of the final decision.

Table 49 ERA Final Decision indirect expenditure ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Recurrent network base costs	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 indirect costs	**169.4**	**169.4**	**169.4**	**169.4**	**169.4**	**847.1**
Network growth escalation	0.3	0.6	0.9	1.5	1.8	5.1
Efficiency	(1.7)	(3.4)	(5.1)	(6.7)	(8.4)	(25.3)
Labour cost escalation	0.5	1.1	1.6	2.1	2.7	8.0
Total indirect costs	**168.5**	**167.7**	**166.8**	**166.3**	**165.5**	**834.9**

Labour cost escalation

407. Western Power has made two changes to its proposed labour cost forecasts in its revised proposal. Western Power obtained updated labour escalation forecasts from its technical consultant, Synergies Economic Consulting, and has amended its proportion of labour costs from 40 per cent to 59.7 per cent for distribution and 70.4 per cent for transmission.

408. In Western Power's initial proposal and the draft decision, labour escalation was applied to the actual proportion of labour costs. In its revised proposal Western Power is seeking to apply a method the AER has used in recent decisions, which is to apply benchmark efficient labour cost proportions rather than actual labour cost component proportions.

409. The ERA does not accept Western Power's proposed revised labour proportions. Using a labour proportion that is not based on its actual labour proportion will result in a value of labour escalation that is not reflective of Western Power's efficient costs.

410. The ERA has determined that the historical proportion for labour of 40 per cent will continue to be used to calculate labour escalation.

411. The ERA has also not accepted Western Power's proposed labour cost per annum percentage values which averaged 1.3 per cent. The ERA has determined that the value of labour escalation to apply over the period of AA4 should be 0.81 per cent.

412. The ERA has used publically available Australian Bureau of Statistics data to determine a premium for the electricity, gas, water and waste water services industry wages growth Australia-wide over all industries Australia-wide. This premium is then added to the annual average of the Western Australian WPI over the AA4 period which is obtained from WA Treasury forecasts. Table 50 below sets out the ERA's determined labour escalation for the AA4 period.

Table 50: Final Decision derivation of approved real labour escalation factor, per cent per annum

Labour Escalation Factor Component	Per Cent
Annual Average of Western Australian WPI over AA4	2.45
Plus Premium of EGWWS WPI over Australian All Industries	0.20
Equals Nominal Labour Escalation Forecast per annum	2.65
Less Forecast Inflation/CPI per annum	1.84
Equals Authority Approved Labour Escalation Factor	0.81

Total operating expenditure

413. Taking into account the considerations of the individual cost line items set out above, network growth escalation, labour cost escalation and other adjustments, Western Power's forecast operating expenditure (as set out in its revised AA4 proposal) was not consistent with the requirements of section 6.40 of the Access Code. The ERA sets out its final decision operating expenditure forecasts in Table 51 below.

Table 51 ERA Final Decision operating expenditure ($ million real June 2017)

Expenditure	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Recurrent network base costs	316.3	316.3	316.3	316.3	316.3	1,581.5
Step changes	-5.0	-5.0	-5.0	-7.5	-12.5	-35.0
Total recurrent network costs	**311.3**	**311.3**	**311.3**	**308.8**	**303.8**	**1,546.5**
Network growth escalation	1.6	3.4	5.4	7.2	8.7	26.3
Efficiency	-3.1	-6.3	-9.4	-12.5	-15.3	-46.6
Non-recurrent network costs	0.5	0.0	0.0	0.0	0.5	1.0
Expensed indirect network costs	42.1	38.4	38.0	47.1	46.4	212.0
Labour cost escalation	1.1	2.3	3.4	4.6	5.6	16.9
Total	**353.5**	**349.1**	**348.7**	**355.2**	**349.7**	**1,756.1**

Required Amendment 4

Western Power must amend its operating expenditure forecasts to be consistent with the values determined by the ERA in this Final Decision as set out in Table 51 above

Opening regulated capital base for AA4

Access Code requirements

414. The capital base is the value ascribed to the network assets used to provide covered services. Where the target revenue for the price control is set by reference to the service provider's approved total costs, section 6.43 of the Access Code provides for the value of capital related costs to be calculated by determining a capital base and calculating a return on the capital base and an amount of depreciation.

415. Section 6.48 of the Access Code requires that the capital base at the start of any access arrangement period, other than the first access arrangement period, be determined in a manner that is consistent with the Access Code objective. A note to section 6.48 indicates that:

> {A number of options are available in relation to the determination of the capital base at the start of an access arrangement period, including:
>
> - rolling forward the capital base from the previous access arrangement period applying benchmark indexation such as the consumer price index or an asset specific index, plus new facilities investment incurred during the previous access arrangement period, less depreciation and redundant capital etc; and
> - valuation or revaluation of the capital base using an appropriate methodology such as the Depreciated Optimised Replacement Cost or Optimised Deprival Value methodology.}

416. Although section 6.48 of the Access Code does not mandate a specific method for determining the capital base, sections 6.51A to 6.63 of the Access Code contemplate new facilities investment being added to the capital base and the value of any redundant assets being subtracted from the capital base, consistent with use of the "roll forward" method for determination of the capital base.

417. Section 6.51A of the Access Code provides that new facilities investment may be added to the capital base if it passes certain tests:

> 6.51A New facilities investment may be added to the capital base if:
>
> (a) it satisfies the new facilities investment test; or
>
> (b) the Authority otherwise approves it being adding to the capital base if:
>
> (i) it has been, or is expected to be, the subject of a contribution; and
>
> (ii) it meets the requirements of section 6.52(a); and
>
> (iii) the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of the addition.

418. The new facilities investment test is set out in section 6.52 of the Access Code:

> 6.52 New facilities investment satisfies the new facilities investment test if:
>
> (a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:
>
> (i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and

(ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either:

A. the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. if a modified test[58] has been approved under section 6.53 and the new facilities investment is below the test application threshold – the modified test is satisfied;

or

(ii) 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; or

(iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

419. Section 6.54 of the Access Code requires that the ERA, in determining whether new facilities investment satisfies the new facilities investment test, must consider whether the new facilities investment was required by a written law or a statutory instrument.

420. Sections 6.61 to 6.63 of the Access Code provide for an amount to be subtracted from the capital base in respect of redundant network assets:

Redundant capital

6.61 Subject to section 6.62, the Authority may in relation to a determination under section 6.44(a) require an amount ("redundant capital") to be removed from the capital base to the extent (if any) necessary to ensure that the network assets which have ceased to contribute in any material way to the provision of covered services are not included in the capital base.

6.62 Before requiring a removal under section 6.61, the Authority must have regard to:

(a) whether the service provider was efficiently minimising costs when it developed, constructed or acquired the network assets; and

(b) the uncertainty such a removal may cause and the effect which any such uncertainty may have on the service provider, users and applicants; and

(c) whether the cause of the network assets ceasing to contribute in any material way to the provision of covered services was the application of a written law or a statutory instrument; and

(d) whether the service provider was compelled to develop, construct or acquire the network assets:

(i) by an award by the arbitrator; or

58 Under the "modified test" referred to in section 6.52(b)(i)B of the Access Code, and set out in section 6.53, the ERA may approve new facilities investment below the threshold value where the ERA determines that approving the access arrangement with the modified test would be efficient and would promote the Access Code objective.

(ii) Because of the application of a written law or a statutory instrument; and

(e) whether the depreciation of the network assets should be accelerated instead of or in addition to a redundant capital amount being removed from the capital base under section 6.61.

6.63 If the Authority requires a removal under section 6.61, then when making other determinations under this Chapter 6 the Authority may have regard to the removal.

{Examples of such other determinations include approving a weighted average cost of capital and assessing the economic life of assets.}

Western Power's proposal

421. Consistent with the current access arrangement, Western Power specified capital base values separately for the transmission and distribution networks.

422. Western Power calculated the capital base values for the transmission and distribution networks for the beginning of the AA4 period using a roll-forward method that involves commencing with the opening value at the beginning of the AA3 period and:

- **adding** the actual values of capital expenditure (new facilities investment) during the AA3 period that Western Power considers meet the requirements of the new facilities investment test under section 6.52 of the Access Code (excluding gifted assets and capital expenditure which is funded by customers via capital contributions);[59]
- **deducting** values of redundant assets and disposals;
- **deducting** values of depreciation as allowed for in target revenue for AA3; and
- **making an escalation** for inflation to be expressed in dollar values at June 2017 prices.

423. Western Power's calculated values of the capital base for the transmission and distribution networks at the commencement of AA4 are set out in Table 52 and Table 53 (below).

Table 52 Western Power's proposed capital base as at 30 June 2017 for the transmission network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	2,816.7	2,942.8	3,177.6	3,215.4	3,156.0	2,816.7
New facilities investment	224.5	342.4	161.2	122.4	106.7	957.2
Asset disposals	(4.4)	(4.2)	(9.3)	(60.6)	(1.5)	(80.0)
Depreciation	(94.0)	(103.4)	(114.1)	(121.3)	(129.4)	(562.2)
Accelerated depreciation						
Closing asset base	2,942.8	3,177.6	3,215.4	3,156.0	3,131.8	3,131.8

[59] Capital expenditure is added to the regulated capital base on an "as incurred" basis rather than an "as commissioned" basis.

Table 53 Western Power's proposed capital base as at 30 June 2017 for the distribution network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	4,248.7	4,709.9	5,144.4	5,506.4	5,752.6	4,248.7
New facilities investment	679.9	671.5	628.9	515.5	364.4	2,860.2
Asset disposals	(0.9)	(0.3)	(4.9)	(2.8)	(0.6)	(9.5)
Depreciation	(214.0)	(236.2)	(261.9)	(266.5)	(281.5)	(1,260.1)
Accelerated depreciation	(3.8)	(0.5)				(4.3)
Closing asset base	4,709.9	5,144.4	5,506.4	5,752.6	5,834.9	5,834.9

Submissions on Western Power's proposal

424. Submissions on the opening capital base for AA4 were incorporated into the ERA's considerations for its draft decision where applicable.

Draft decision

425. The ERA considered whether Western Power's calculation of the capital base for the transmission and distribution networks was consistent with the requirements of the Access Code. These considerations were documented below in the following order:

- the general method applied in calculating the capital base;
- verification that stated capital expenditure during AA3 actually occurred; and
- determination of the capital base at the commencement of AA4, taking into account:
  - an assessment of actual capital expenditure in AA3 against the test in section 6.51A of the Access Code;
  - depreciation; and
  - redundant assets.

General method

426. In its initial proposal, Western Power calculated the capital base for each of the transmission and distribution networks using a roll-forward method. This method was used for AA2 and AA3 and is consistent with the method described in the note to section 6.48 of the Access Code.

427. The roll-forward method is generally used by utility regulators throughout Australia and is the method mandated for electricity transmission and distribution networks in the National Electricity Market under chapters 6A and 6 of the National Electricity Rules.

428. Perth Energy submitted that the opening capital base should be based on the cost of replacement rather than rolling forward previous balances and indexing by CPI. It noted assets that are redundant, or would not need to be replaced today, should have a value of zero. It also considered real deprecation should not be used:

> The revenue allowed for deprecation in real terms has the potential to create a cash "glut" within Western Power, and a situation where the value of Western Power is not diminished as its assets diminish in value over time, as the loss of value in physical assets is replaced with cash, creating value "neutrality" in real terms within Western Power.

429. Regulatory frameworks such as the Access Code provide for a return on efficient capital investments in assets that are required to provide regulated services as well as the return of the assets over their economic lives. Depreciation is an input into the calculation of regulated charges.

430. The issue raised by Perth Energy suggested Western Power is recovering more than its efficient investment. A service provider's cash flow will vary over time depending on such factors as the replacement lifecycle of assets. However, the regulatory framework ensures the service provider's target revenue only includes a regulatory depreciation allowance equal to (in real terms) the value of its initial capital investment and that assets are fully depreciated by the end of their economic lives.

431. The ERA in its draft decision did not consider that Perth Energy's concern is a likely outcome given the checks and balances provided in the Access Code including the ability to provide for redundant assets.

432. The roll-forward method used by Western Power to establish the opening capital base for AA4 was consistent with the Access Code objective.

Verification of capital expenditure in AA3

433. In accordance with the ERA's Guidelines for Access Arrangement Information, Western Power provided regulatory accounts that reconciled the costs of regulated activities with a set of base accounts for the business. These regulatory accounts provided a reconciliation of claimed new facilities investment with actual capital costs incurred for 2012/13 to 2016/17 as shown in Table 54 (below).

Table 54 Reconciliation of claimed new facilities investment with recorded capital costs ($ million real June 2017)

	Base Account	Adjustments	Regulatory Account	Claimed new facilities investment
Transmission 2012/13:				
Capital expenditure	250.4	(7.5)	242.8	242.8
Contributions	(19.6)	(0.4)	(19.2)	(19.2)
Net expenditure	230.8	(7.9)	223.6	223.6
Transmission 2013/14:				
Capital expenditure	353.9	(12.2)	341.7	341.7
Contributions	(24.4)	22.6	(1.8)	(1.8)
Net expenditure	329.5	10.4	339.9	339.9
Transmission 2014/15:				
Capital expenditure	177.9	(12.2)	165.7	165.7
Contributions	(13.6)	8.6	(5.0)	(5.0)
Net expenditure	164.3	(3.6)	160.7	160.7
Transmission 2015/16:				
Capital expenditure	128.6	(2.2)	126.4	126.4
Contributions	(7.3)	1.8	(5.5)	(5.5)
Net expenditure	121.3	(0.4)	120.9	120.9
Transmission 2016/17:				
Capital expenditure	119.1	(0.9)	118.2	118.2
Contributions	(3.0)	(12.3)	(15.3)	(15.3)
Net expenditure	116.1	(13.2)	102.9	102.9
Distribution 2012/13:				
Capital expenditure	771.4	0.0	771.4	771.4
Contributions	(109.2)	12.2	(97.0)	(97.0)
Net expenditure	662.2	12.2	674.4	674.4
Distribution 2013/14:				
Capital expenditure	774.0	0.0	774.0	774.0
Contributions	(113.8)	6.6	(107.2)	(107.2)
Net expenditure	660.2	6.6	666.8	666.8
Distribution 2014/15:				
Capital expenditure	704.6	0.0	704.6	704.6
Contributions	(93.9)	14.4	(79.5)	(79.5)
Net expenditure	610.7	14.4	625.1	625.1
Distribution 2015/16:				
Capital expenditure	606.4	0.0	606.4	606.4
Contributions	(79.1)	(13.5)	(92.6)	(92.6)
Net expenditure	527.3	(13.5)	513.8	513.8

	Base Account	Adjustments	Regulatory Account	Claimed new facilities investment
Distribution 2016/17:				
Capital expenditure	457.9	0.0	457.9	457.9
Contributions	(98.1)	4.7	(93.4)	(93.4)
Net expenditure	359.8	4.7	364.5	364.5

434. The adjustments in the regulatory accounts included:

- removing capitalised borrowing costs that are not properly recorded as capital expenditure in the regulatory accounts; and
- restating capital contributions to be on a cash received basis.

435. The regulatory accounts were audited by the Office of the Auditor General.

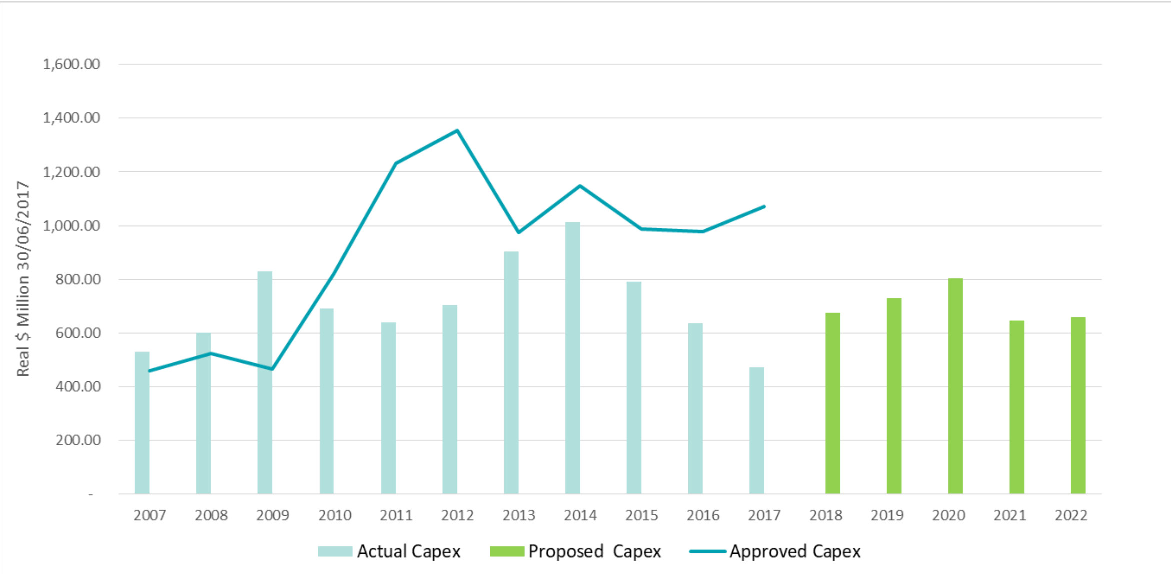
436. The adjustments made in the regulatory accounts were appropriate and consistent with previous practice.

Capital base at the commencement of AA4

Capital expenditure during AA3

437. A comparison of forecast and actual capital expenditure (net of capital contributions and gifted assets) since the network became regulated is shown in Figure 9.

Figure 9 Western Power net capital expenditure (excluding gifted assets and cash contributions)



438. Capital expenditure in AA3 was higher than in AA2 primarily due to construction expenditure on the Mid-West energy project, which made up almost 40 per cent of

total AA3 transmission capex and is Western Power's largest one-off capital expenditure project in more than 25 years.[60]

439. As seen in Figure 9 (above), Western Power spent significantly below the amount forecast for AA3. Transmission expenditure was $957.23 million or 43.1 per cent below the forecast, and distribution expenditure was $2,860.26 million or 17.7 per cent below the forecast.

440. A comparison of Western Power's actual capital expenditure with approved expenditure during AA3 for transmission and distribution is set out in Table 55 and Table 56 (below).

Table 55 Western Power AA3 actual and forecast transmission capital expenditure ($ million real June 2017)

Expenditure	Actual	Forecast	Difference
Growth	517.2	1,154.2	(637.0)
Asset replacement and renewal	186.3	184.1	2.2
Improvement in service	60.3	84.3	(24.0)
Compliance	111.9	135.6	(23.6)
Corporate	81.6	125.8	(44.2)
Total	**957.2**	**1,683.8**	**(726.6)**

Table 56 Western Power AA3 actual and forecast distribution capital expenditure ($ million real June 2017)

Expenditure	Actual	Forecast	Difference
Growth	592.1	1,083.9	(491.8)
Asset replacement and renewal	1,613.0	1,579.8	33.3
Improvement in service	24.6	35.8	(11.2)
Compliance	460.5	567.9	(107.4)
Corporate	170.2	208.9	(38.7)
Total	**2,860.3**	**3,476.1**	**(615.8)**

441. The main reasons for differences between forecast and actual expenditure were set out as follows.

Growth

442. Growth expenditure was the largest underspend for transmission and distribution. The ERA's technical adviser, GBA, observed in its report that:

---

[60] Geoff Brown and Associates, *Review of Western Power's Actual Capital Expenditure during AA3 (Final)*, 10 April 2018, p. 7.

> The demand growth forecast at the time of the AA3 review has not materialised and Western Power is now putting much more focus on quantifying the risk of deferring or not proceeding with a capacity expansion project and on identifying lower cost means of mitigating that risk. This has led to 40 of 68 capacity expansion capital projects in the approved forecast not proceeding during AA3. Many projects that have proceeded have come in under budget.

443. The distribution growth capital expenditure underspend was also primarily due to the decline in the rate of demand growth which can be attributed to the sluggish state economy, a substantial increase in behind-the-meter solar generation and the impact of energy efficiency initiatives.

444. Growth expenditure is subject to the investment adjustment mechanism. This ensures the return on investment included in Western Power's AA3 target revenue is adjusted to reflect the underspend. Target revenue is adjusted for AA4 to return this revenue to users.

Asset replacement and renewal

445. Asset replacement and renewal expenditure was broadly in line with forecasts for transmission and distribution.

446. Western Power's transmission replacement and renewal expenditure of $187 million was consistent with its forecast expenditure of $184 million for the AA3 period. However, there were differences between sub-categories due to the Muja power transformer replacement expenditure, which resulted in power transformer expenditure being 160 per cent higher than forecast and a reallocation from other sub-categories, in particular from switchboard replacement.

447. Asset replacement and renewal expenditure for the distribution network totalled $1,675.07 million for AA3, which was overspent by 3 per cent compared to forecast expenditure of $1,627.80 million. The asset replacement and renewal category included the significant expenditure projects of wood pole management and distribution conductor replacement.

448. Metering expenditure was also included in asset replacement and renewal. Synergy considered Western Power's proposed target revenue should be adjusted to remove the capital and operating expenditure approved at AA3 for Western Power's proposed smart grid that was not used for that purpose.

449. The ERA's draft decision determination of forecast capital expenditure did not set limits on specific projects Western Power was to undertake. During the access arrangement period, Western Power is free to manage its expenditure 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.

450. Asset replacement and renewal expenditure is not subject to the investment adjustment mechanism.

Improvement in service

451. Improvement in service expenditure for transmission and distribution was underspent by $35.2 million during the AA3 period.

452. Western Power states a number of planned projects were deferred due to resources being directed to other high priority projects, including business transformation

initiatives, and uncertainty about changes to the energy market rules as a result of the State Government's electricity market review initiatives. Additional cost efficiencies were achieved by changes to asset management strategies that extended asset lives into the AA4 period.

Compliance

453. Western Power advised that the under-spend in transmission compliance expenditure was a result of deferral of work in a number of the sub-categories due to reprioritisation of the works program and reallocation of resources to emergency projects.

454. Western Power also noted that substation security, a sub category of transmission compliance, had its program of works delayed during the period due to the very high capital cost of some security fencing proposals. The delay allowed additional detailed planning of requirements for different types of fencing and the program recommenced later in the AA3 period.

455. Western Power advised that the under-spend in distribution compliance expenditure was due to the completion of safety programs, including the replacement of all known streetlight switch wire and at-risk overhead customer service connections. Western Power states it has also introduced zonal treatment instead of standalone programs for some asset categories, which resulted in a reduction of replacement volumes as only known defects in each zone were addressed. Finally, it identified and adopted alternative risk based treatment options to address some compliance issues.

Corporate

456. Western Power stated that both corporate real estate and property, and plant and equipment actual expenditure were less than forecast due to a delay in re-building a number of its depots which was forecast to take place during AA3.

Application of the new facilities investment test to actual capital expenditure

457. In order to include the actual capital expenditure incurred during AA3 in the capital base, Western Power must satisfy the ERA that the expenditure meets the new facilities investment test under section 6.52 of the Access Code.

458. The new facilities investment test of section 6.52 of the Access Code comprises two parts.

459. The first part of the new facilities investment test 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. This is hereafter referred to as the "efficiency test".

460. 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:

- 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”).

461. Expenditure that does not meet the new facilities investment test cannot be added to the capital base and recovered through regulated network tariffs.

462. Expenditure that does not meet the new facilities investment test needs to be financed by some other means or is otherwise unrecoverable through regulated network tariffs. This would typically be a capital contribution from the user of the network whose service application gives rise to the need for the investment.

463. The ERA sought advice from its technical consultant GBA to assist its consideration of whether Western Power’s AA3 expenditure was consistent with the requirements of the new facilities investment test.

464. GBA’s review included an assessment of:

- the extent to which Western Power applied its expenditure management governance processes in the development, approval and implementation of the project or program;
- the justification for any positive or negative variance between the estimated cost at the time of project or program approval and the final project or program cost;
- the justification for project or program implementation schedule changes; and
- the scope of the forecast project compared to the scope at the time of project approval.

465. GBA’s review of AA3 capital expenditure for compliance with new facilities investment test requirements was undertaken using both top-down and bottom-up analyses. GBA’s top-down analysis involved comparing capital expenditure in different asset categories with both the equivalent expenditure during AA2 and the forecast expenditure for AA3, as approved by the ERA during the AA3 regulatory review.

466. GBA sought further explanation from Western Power to justify expenditure that appeared abnormally high.

467. GBA’s bottom-up approach included a review of a sample of capital projects undertaken during AA3 to assess whether these projects individually met the new facility investment test requirements.

468. From its review, GBA observed 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.

469. While GBA has observed improved efficiency in Western Power's management of its capital expenditure, GBA identified a number of projects in full or part that it considered did not meet the new facility investment test requirements. These projects are considered further below.

Summary of compliance with the new facilities investment test

470. The ERA reviewed the information provided by Western Power, submissions received from stakeholders and the advice received from its technical consultant.

471. Synergy's submission raised concerns that Western Power had not adequately justified that all expenditure during AA3 met the new facilities investment test noting:

> WP's internal processes for assessing new facilities investment (see AAI Attachment 5.1 at sections 3.2 to 3.4) do not include any requirement to identify various options for dealing with an identified risk/requirement and to assess (e.g. via cost-benefit analysis) which option offers the most efficient way to manage the identified risk/requirement. If WP does not properly identify and assess alternative options, there is a risk a sub-optimal option will be adopted, which is unlikely to satisfy the goal of efficiently minimising costs.

472. Based on the information submitted by Western Power and the advice from its technical consultant, Western Power's internal processes during AA3 were in most instances adequate and Western Power's expenditure met the new facilities investment test.

473. However, the ERA identified several projects that did not meet the new facilities investment test with reasons for this set out below. In summary, the expenditure identified as not meeting the new facilities investment test was made up of:

- Transmission:
  - $2.1 million capital expenditure for the undergrounding of the Manning-Osborne Park 132 kV transmission line in Ewen Street, Woodlands; and
  - $0.7 million for a transmission capital contribution for the Medical Centre substation.
- Distribution:
  - $7.1 million provision for the future decommissioning and site restoration of the Shenton Park, Herdsman's Parade, British Petroleum and Durlacher substations;
  - $1.8 million distribution capital expenditure for the Perenjori battery storage system project; and
  - $28.9 million distribution expenditure for wood poles which should have been included in operating expenditure.
- Corporate:
  - $2.1 million for a corporate provision for the removal of asbestos from Western Power's offices; and

- $6.7 million corporate costs capitalised for intellectual property completed in preparation for a transition to the national regulatory regime.

474. In addition, the ERA had concerns that expenditure on the head office refurbishment (Project Vista) and wood pole program may not have been consistent with the new facilities investment test and was to give further consideration to this in its final decision.

475. The draft decision amended new facilities investment is set out in Table 57 below, followed by a discussion of each item.

Table 57 Draft decision amounts of new facilities investment in the AA3 period to be added to the capital base ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Total transmission new facilities investment claimed by Western Power	**224.5**	**342.4**	**161.2**	**122.4**	**106.7**	**957.2**
Manning-Osborne Park 132kV line		(0.1)	(1.9)			(2.0)
Medical centre substation capital contribution	(0.7)					(0.7)
Asbestos removal provision	(0.7)					(0.7)
Capitalisation of intellectual property for work completed in preparation for a transition to the national regime (share)	(2.3)					(2.3)
Value to be added to the transmission capital base	**220.8**	**342.3**	**159.3**	**122.4**	**106.7**	**951.5**
Total distribution new facilities investment claimed by Western Power	**679.9**	**671.5**	**628.9**	**515.5**	**364.4**	**2,860.2**
Wood poles expenditure included in operating expenditure			(10.5)	(12.9)	(5.5)	(28.9)
Perenjori battery storage system				(0.3)	(1.5)	(1.8)
Future decommissioning costs for various substations	(7.1)					(7.1)
Asbestos removal provision	(1.4)					(1.4)
Capitalisation of intellectual property for work completed in preparation for a transition to the national regime (share)	(4.4)					(4.4)
Value to be added to the distribution capital base	**667.0**	**671.5**	**618.4**	**502.3**	**357.4**	**2,816.6**

Manning – Osborne Park transmission line undergrounding

476. Following inquiries from the ERA and its technical consultant regarding this project, Western Power advised that it considered the expenditure did not meet the new

facilities investment test and the expenditure had been included in the AA4 submission due to an oversight.

Medical centre substation

477. Western Power advised that it received a $0.7 million bring-forward customer contribution for this project. As capital contributions do not meet the new facilities investment test requirements to be included into the regulatory capital base, $0.7 million was excluded from the regulatory capital base for AA4.

Wood poles reclassification of expenditure

478. This is considered below under wood pole expenditure.

Perenjori battery energy storage system

479. During the AA3 period, Western Power installed a battery energy storage system to improve reliability of supply to users in Perenjori, supplied by the Morawa feeder supplied from the Three Springs zone substation.

480. Western Power's business case identified that some of the expenditure did not meet the new facilities investment test, however, this was overlooked when preparing the AA4 submission.

481. Western Power advised the ERA that $1.78 million of the total expenditure of $3.83 million does not meet the new facilities investment test and should not be included in the opening capital base.

Decommissioning provisions

482. Western Power included $7.13 million in its AA3 transmission capacity expenditure that had been characterised as decommissioning provisions. Western Power described these costs as:

> … capitalised decommissioning costs for assets meeting the asset recognition criteria stated in Western Power's capital expenditure and depreciation standard; and in compliance with paragraph 16c of Australian accounting standard AASB116, Property Plant and Equipment.

483. Western Power justified its treatment as follows:

- Paragraph 16c of the Australian Accounting Standards Board (**AASB**) standard 116 provides that the cost of an item of property should include the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located.
- AASB 137-Provisions, Contingent Liabilities and Contingent Assets provides that a provision shall be recognised where a legal or constructive obligation has arisen from a past event that will more likely result in an outflow of benefits, and the amount can be measured reliably. Western Power's legal obligation towards land rehabilitation arise from the completion and/or removal of an asset (past event) and it is highly probable that this obligation will result in the outflow of benefits and that the amount can be measured reliably.

484. Paragraph 16c of AASB would not normally apply to the construction of new transmission and distribution assets on a greenfield site since it is generally assumed that at the end of an asset's economic life an asset will need to be replaced and the

cost of decommissioning and removing the asset would be included in the cost of installing its replacement. Western Power stated it recognised this and only capitalised decommissioning provisions for sites no longer required.

485. Section 6.49 of the Access Code states that the RAB must not include *forecast* new facilities investment. As a provision is a forecast, the decommissioning provisions were not consistent with the requirements of section 6.49 of the Access Code. Consequently, this amount was to be removed from the opening capital base for AA4.

Asbestos provision

486. Western Power has included a provision of $2.64 million for the removal of asbestos from across its network including its Murray Street offices, depots and substations.

487. Western Power advised the provision was raised for all identified remedial work necessary for asbestos removal as per accounting standard requirements and of the initial $2.6 million provision, $546,000 was for works completed in the AA3 period.

488. As noted above, section 6.49 of the Access Code does not permit forecast expenditure to be included in the capital asset value. Consequently, the remaining value of the provision ($2.1 million being $2.6 million less $0.5 million) was to be removed from the opening capital base.

Intellectual property

489. Western Power proposed to include $6.70 million for intellectual property for work completed in preparation for transition to the national electricity network regulation regime. Western Power did not suggest that the expenditure met the new facilities investment test requirements but that rather, it was covered under the unforeseen event adjustments mechanism.

490. GBA advised:

> We do not see any justification for including any expenditure related to possible transition to the NER in the AA4 opening RAB and note that:
>
> - intellectual property is, by definition, an intangible asset and it is not usual to include intangible assets in the regulatory asset base of an electricity lines business;
> - the state government has indicated that it has no plans for Western Power to be regulated by the Australian Energy Regulator under the NER;
>
> Furthermore, the code defines the capital base (or RAB) as the value of network assets used to provide covered services. Network assets are defined as:
>
> - the apparatus, equipment, plant, and buildings used to provide or in connection with providing covered services on the network, which assets are either connection assets or shared assets.
>
> This definition would appear to preclude intangible assets being included in the RAB.

491. An intangible asset of the nature Western Power described would not fall within the definition of network assets.

492. In any case, as the expenditure was not required to meet an obligation and did not deliver any value to customers, it did not meet the requirements of section 6.52(b)

of the Access Code. Consequently, the ERA considered that the expenditure could not be included in the opening capital base.

Project Vista

493. The ERA's technical consultant identified Project Vista as not meeting the new facilities investment test. GBA noted:

> This was a legacy project commenced in 2008 and inherited by Western Power's current Board and management.

494. GBA considered project inefficiencies arose from the high quality of the internal fitout and a loss of control of project costs during implementation. GBA considered some of these inefficiencies could be removed by not allowing the full $10 million capital expenditure incurred during AA3. GBA was not able to recommend the quantity of any such reduction.

495. The project stretched over more than seven years and three access arrangement periods. There were inefficiencies in project management, during that period, particularly between October 2008 and November 2010 when cost variations of $13.4 million, 20 per cent of the original cost, were incurred.

496. The ERA has in the past identified deficiencies in Western Power's design and governance of capital projects that had led to inefficiencies. As a consequence, the ERA excluded $261 million of capital expenditure incurred in AA1 from Western Power's regulated capital base.[61]

497. As noted by GBA, Project Vista was inherited by Western Power's current Board and management. It would be difficult to attribute inefficiencies directly to the expenditure incurred during the AA3 period as it was affected by project management during previous periods.

Distribution wood pole program

498. At the time of submitting its AA3 proposal, Western Power was subject to EnergySafety Order 01-2009 for its distribution wood pole network. A requirement of the Order was that Western Power replace or reinforce unsupported rural wood poles that did not meet specified wind speed design criteria by 31 December 2015.

499. At the time of the AA3 submission Western Power estimated that this would involve the replacement of 140,000 wooden poles and the reinforcement of up to 110,000 poles. Western Power considered this volume of replacements and reinforcements was undeliverable, and based its AA3 wood pole replacement forecast on the replacement of 100,000 poles and reinforcement of a further 64,000 poles by the end of AA3.

500. In its further final decision for the AA3 period, the ERA accepted Western Power's proposal on the basis that, while it would not fully meet the requirements of the Order, it was the most that could be expected to be achieved given financial and deliverability constraints.

[61] Economic Regulation Authority, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 29 March 2012, paras. 18 and 45.

501. The ERA's decision also included wood pole replacements in the access arrangement's investment adjustment mechanism, which meant that if Western Power was able to treat more poles than forecast, the additional expenditure would be funded provided it met the new facility investment test requirements.

502. GBA indicated that at the time of submitting its AA3 proposal, Western Power faced three problems that constrained its ability to fully comply with the EnergySafety Order:

- Western Power had not found a method that would reliably assess the condition of its hardwood poles and, partly because of this, did not have a management plan in place that would allow it to identify individual hardwood poles that required replacement in accordance with the Order. Western Power's solution was to replace or reinforce all hardwood poles in rural areas that had been in service for 25 years or longer.
- Western Power did not have the delivery capacity to replace or reinforce the number of poles that would need to be replaced in accordance with its deterministic replacement policy. There was only one pole reinforcement contractor available that was acceptable to Western Power and this contractor had capacity limitations.
- Western Power considered the total cost of complying with the Order was prohibitive, given the number of poles believed to require treatment under its deterministic treatment policy.

503. In implementing its wood pole replacement program, the Western Power board approved two business cases for the replacements and reinforcements program. The first business case in May 2012 covered the first two years of AA3 and the second business case in March 2014 covered the final three years of AA3.

504. During the first half of 2016, EnergySafety reviewed Western Power's compliance with its order and on 10 June 2016 issued a report that found that:

> …the principal public safety objectives set out in the Order have been achieved. The Director of Energy Safety is therefore satisfied that Western Power has complied with the Order as at 31 December 2015.

505. The review found that:

- Western Power had replaced or reinforced to a safe standard all hardwood poles on its rural network by 31 December 2015 and in doing so met the intent of the order. It made this determination using a statistically valid sampling process; and
- Western Power had improved its wood pole management plan to the point where EnergySafety considered it to be an acceptable basis for managing the safety risks of its wood pole fleet going forward.

506. Synergy submitted that although the work undertaken by Western Power on wood poles may have been required to meet the EnergySafety Order, this did not necessarily mean it met the new facilities investment test as Western Power had to also demonstrate that the works it implemented were the best way to efficiently minimise costs.

507. Western Power replaced and reinforced fewer poles than forecast for the total AA3 period. However, during the first few years of AA3, the number of poles replaced and reinforced, and corresponding expenditure, was higher than forecast.

508. The ERA's technical consultant advised:

> … expenditure was significantly higher in the first years of AA3 because poles were replaced that in hindsight were still in satisfactory condition and were not overloaded. At the time Western Power was under intense pressure from both EnergySafety and the Government to reduce the public safety risk of its wood pole fleet and to comply with the requirements of the EnergySafety Order. It now uses a much improved wood pole management strategy, which we understand analyses the need to replace or reinforce each individual pole using highly granular data that has been developed over several years and required a significant investment in research and development. It was not available to Western Power until the middle of the AA3 period.
>
> Over the whole of AA3, Western Power has replaced 15 per cent less poles and reinforced 29 per cent less poles than forecast at the beginning of the period. Notwithstanding this, EnergySafety has confirmed that Western Power has fully complied with the intent of its 2009 Order and has also endorsed its current wood pole management strategy as an appropriate basis for managing its wood pole fleet going forward.

509. The ERA also considered the costs of the program. Total actual costs were 5.9 per cent less than forecast. The reduced expenditure was a combination of lower than forecast volumes and higher than forecast unit rates.

510. As noted above, Western Power undertook 15.6 per cent less replacements and 28.7 per cent less reinforcements compared to the forecast volumes for the AA3 period. The unit rate for replacements was 31.7 per cent above forecast while reinforcements were 10.2 per cent below forecast.

511. Western Power provided reasons why the unit costs for replacements were above the forecast amounts. The reasons included:

- the need for greater utilisation of external contractors with higher unit rates to ramp up delivery to meet the Order;
- a higher proportion of complex poles being treated than forecast based on historical rates (for example, it costs more to replace a transformer pole than a pole that supports only a phase and earth conductor);
- more accurate recording of work types (now four different pole types and their corresponding costs can be tracked, rather than a single average); and
- a change to the accounting treatment of unplanned pole replacements which increased the proportion of the replacement cost capitalised from around 40 per cent to 100 per cent.

512. The ERA requested additional information from Western Power on the change in accounting treatment for unplanned pole replacements. Western Power advised that, prior to AA3, data quality issues meant obtaining accurate and reliable information to perform asset disposals was not possible. As a result of these data issues, the method previously in place estimated the net cost of the asset by using a percentage of total cost based on the estimated life of the asset.

513. Western Power adopted this method because the true cost of the unplanned replacement could not be correctly accounted for, nor could the specific details of the asset being replaced. To avoid over-inflating the value of fixed assets, Western Power only capitalised a portion of each job, with the remainder left as operating expenditure and no disposal recorded.

514. From November 2013, improvements in data quality enabled Western Power to calculate asset disposals and capitalise 100 per cent of the replacement cost.

515. The method in place prior to November 2013 resulted in 40 per cent of the costs being allocated to capital expenditure and 60 per cent of the costs allocated to operating expenditure. The AA3 capital and operating expenditure forecasts would have been prepared on the basis of this 40/60 split.

516. As this method changed during the period and Western Power had from November 2013 capitalised the remaining 60 per cent of the costs of unplanned wood pole replacements that was previously regarded as operating expenditure, if Western Power were to roll this expenditure into the capital base it would effectively be double counting the costs as it had received the 60 per cent as an operating expenditure allowance for AA3.

517. From the additional information provided by Western Power, the total amount for the years 2014/15, 2015/16 and 2016/17 for unplanned pole replacements was $48.2 million. Sixty per cent of this expenditure equates to $28.9 million that was required to be removed from the capital base to avoid double counting.

518. The ERA recognised a combination of circumstances may, with the benefit of hindsight, have led to unnecessary pole replacements or reinforcements during the first few years of AA3. However, as Western Power did not have its improved wood pole management strategy ready in time to meet EnergySafety's standards, it appears the only option available to Western Power during the first few years of AA3 was the age-based criteria that it used.

519. Making a retrospective adjustment would be difficult, in terms of estimating the number of poles that would not have needed to be replaced based on Western Power's current risk based approach.

520. The ERA's technical consultant's review of the program did not identify inefficiencies in the delivery of the program. Although the unit costs were higher than forecast, Western Power was not able to provide reasons for those differences.

521. As set out above, the ERA required $28.9 million to be excluded from the opening capital base to be consistent with the AA3 decision which assumed such expenditure was included in operating expenditure.

Redundant assets and disposals

522. During the AA2 review, the ERA determined that the value of any revenues from the disposal of assets should be added to the value of redundant assets applied in the calculation of the capital base.

523. Western Power followed this process in its calculation of the opening capital base for the AA4 period by deducting asset disposals based on the gross asset sales proceeds.

524. Submissions from Alinta, Bluewaters, Emergent Energy and ERM Power suggested consideration should be given to whether declines in peak demand could result in under-utilisation of assets and whether some of the existing asset base should be written down as a consequence of this.

525. Section 6.62 of the Access Code provides for the regulator to remove amounts from the capital base to the extent necessary to ensure that network assets which have ceased to contribute in any material way to the provision of covered services are not included in the capital base. Before doing so the Access Code requires that the ERA must have regard to:[62]

(a) whether the service provider was efficiently minimising costs when it developed, constructed or acquired the network assets; and

(b) the uncertainty such a removal may cause and the effect which any such uncertainty may have on the service provider, users and applicants; and

(c) whether the cause of the network assets ceasing to contribute in any material way to the provision of covered services was the application of a written law or a statutory instrument; and

(d) whether the service provider was compelled to develop, construct or acquire the network assets:

(i) by an award by the arbitrator; or

(ii) because of the application of a written law or a statutory instrument; and

(e) whether the depreciation of the network assets should be accelerated instead of or in addition to a redundant capital amount being removed from the capital base under section 6.61.

526. It was not clear that peak demand had declined to the extent that it is possible to identify assets that no longer contribute to providing covered services, even though Western Power's forecasts suggested peak demand was expected to be flat to slightly declining over the AA4 period.

527. The Access Code and other regulatory frameworks in Australia and other jurisdictions encourage service providers to undertake efficient investment by providing a return of their investment (i.e. depreciation) in the regulated revenue stream and for the investment to be recovered over the economic life of the assets. As required under section 6.62 of the Access Code, identifying and removing redundant assets requires careful consideration of a range of factors.

528. The ERA intends to monitor asset utilisation during AA4 to inform its decision at the next access arrangement review.

Depreciation

529. The current access arrangement specifies the depreciation of the opening capital base for AA4 is the forecast depreciation included in the AA3 target revenue.

530. The ERA is satisfied that the depreciation values, including accelerated depreciation values, used in Western Power's calculation of the opening capital base for AA4 are consistent with the depreciation values included in the AA3 target revenue.

Capital base at the commencement of AA4

531. The ERA calculated revised values of the capital base for the transmission and distribution networks as at 30 June 2017 in accordance with the ERA's determination

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[62] *Electricity Networks Access Code 2004* section 6.62.

under its draft decision on the value of new facilities investment in the AA3 period that may be added to the capital base under section 6.51A of the Access Code.

532. The ERA's draft decision calculation of the revised capital base values are shown in Table 58 and Table 59 below.

Table 58 ERA draft decision capital base as at 30 June 2017 for the transmission network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	2,816.7	2,939.1	3,173.7	3,209.7	3,150.2	2,816.7
New facilities investment	220.8	342.3	159.3	122.4	106.7	951.5
Asset disposals	(4.4)	(4.2)	(9.3)	(60.6)	(1.5)	(80.0)
Depreciation	(94.0)	(103.4)	(114.1)	(121.3)	(129.4)	(562.2)
Accelerated depreciation						
Closing asset base	2,939.1	3,173.7	3,209.7	3,150.2	3,126.0	3,126.0

Table 59 ERA draft decision capital base as at 30 June 2017 for the distribution network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	4,248.7	4,496.9	5,131.4	5,483.0	5,716.0	4,248.7
New facilities investment	667.0	671.5	618.4	502.3	357.4	2,816.6
Asset disposals	(0.9)	(0.3)	(4.9)	(2.8)	(0.6)	(9.5)
Depreciation	(214.1)	(236.2)	(261.9)	(266.5)	(281.5)	(1,260.2)
Accelerated depreciation	(3.8)	(0.5)				(4.3)
Closing asset base	4,696.9	5,131.4	5,483.0	5,716.0	5,791.3	5,791.3

Western Power's revised proposal

533. Western Power's revised proposal did not accept the ERA's draft decision.

534. Western Power's proposed revised Opening Capital Base calculations for the transmission and distribution networks are shown in Table 60 and Table 61 below:

Table 60 Western Power revised capital base as at 30 June 2017 for the transmission network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	2,816.7	2,928.6	3,163.2	3,199.2	3,138.0	2,816.7
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						
Closing asset base	2,928.6	3,163.2	3,199.2	3,138.0	3,113.8	3,113.8

Table 61 Western Power revised capital base as at 30 June 2017 for the distribution network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	4,248.7	4,707.8	5,142.3	5,504.4	5,746.2	4,248.7
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)				(4.3)
Closing asset base	4,707.8	5,142.3	5,504.4	5,746.2	5,827.1	5,827.1

535. Western Power has accepted in full the following exclusions set out by the ERA in the draft decision:

- $2.0 million from transmission expenditure for the Manning-Osborne Park line undergrounding;
- $6.7 million for the capitalisation of intellectual property for work completed in preparation for a transition to the national regime split between both transmission and distribution;
- $1.8 million from the distribution network for the Perenjori battery storage system.

536. Western Power has also accepted that expenditure for the future decommissioning of various substations and a provision for asbestos removal do not meet the new facilities investment criteria for inclusion in the opening capital base for AA4. However, Western Power has excluded amounts additional to those proposed by the ERA in the draft decision.

537. The ERA excluded provisions for the decommissioning of a number of Western Power substations as Section 6.49 of the Access Code states that the RAB must not include forecast new facilities investment. Western Power has accepted the ERA's interpretation of the Access Code and removed all provisions for the decommissioning of substations from the opening capital base.

538. In the draft decision, the ERA excluded $7.1 million in decommissioning provisions. Western Power in its response has identified $13.0 million of decommissioning provisions for exclusion that were previously included in the initial proposal of the AA4 opening capital base.

539. Western Power notes in its revised proposal that it has identified that the closing 2016/17 asbestos removal provision was $2.6 million, and has excluded this amount from the AA4 opening capital base.

540. Western Power has not accepted two exclusions set out in the draft decision being the $0.7 million capital contribution for the Medical Centre substation and the $28.9 million of distribution wood pole expenditure that the ERA determined was double counted as a result of a change in accounting treatment during the AA3 period.

Medical centre substation

541. Western Power in its response to the draft decision notes that it did receive a $0.7 million capital contribution for the project, however, this amount was not included in the opening AA4 RAB.

542. The capital contribution was received in the 2012/13 period and was included in the capital contribution figures in the AA4 revenue model. As the revenue model includes total gross capital expenditure and then deducts capital contributions received, Western Power states that the contribution has been appropriately excluded from the opening RAB calculations.

Distribution wood pole program

543. Western Power notes in its response to the draft decision that the change in accounting treatment for unplanned pole replacements during AA3 adds complexity to the assessment of wood pole expenditure and it understood why the ERA might consider there to be a double count of expenditure as a result.

544. Western Power notes that because the accounting method changed mid-period, and is therefore different to the accounting method in place when making Western Power's AA3 revenue determination, that 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.

545. Western Power states that this is because the ERA has assumed 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 operating expenditure component of AA3 target revenue.

546. Western Power states 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.

547. Western Power notes that the capitalisation treatment of 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.

548. Further, Western Power noted that as a result the 60 per cent of capitalised costs for 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.

549. Western Power noted the ERA's technical consultant (GBA), conducted a thorough review of Western Power's new facilities investment for wood poles during the AA3 period and determined that the program satisfied the NFIT, was lower than the approved expenditure forecast and resulted in improved asset management strategies during the period.

550. Western Power submits that, consistent with the advice of GBA, the wood pole replacement capital expenditure during the AA3 period satisfied the requirements of the NFIT and should be included in the AA4 opening RAB.

Submissions on draft decision

551. Submissions on the ERA's draft decision were received from Perth Energy and the Western Australia Major Energy Users (WAMEU). These submissions are set out below.

552. Perth Energy

In its initial submission to the ERA, Perth Energy questioned the decision to use the roll forward method of valuation for the Regulated Asset Base (RAB). Perth Energy is of the view this method is inconsistent with promoting efficient investment in the network. The ERA's response to this concern was found in paragraph 255 of its draft decision. The ERA states that it:

> "*considers the roll-forward method is consistent with the access code*" (para 255)

Perth Energy is glad the ERA has made its position on valuation of the RAB known, but is disappointed with its lack of an explanation. Perth Energy is of the view that there are many valuation methods of the regulated asset base that are available, but a reason as to why:

> i) The roll-forward method is consistent the code objectives above, or
>
> ii) The roll-forward method is the best valuation method, given the alternatives.

given the price increase for transmission connected customers would be appreciated.

As per paragraph 253 of the ERA's draft determination, the ERA states:

> *"the service providers target revenue only includes a regulatory depreciation allowance equal to (in real terms) the value of its initial capital investment." (para 253)*

Structuring the recovery of revenue in this way that is consistently linked to the historical cost of investment, creates an effective 'break-even' guarantee for Western Power for any asset included in the RAB, irrespective of its current value to the SWIS. Perth Energy would be interested in how the ERA came to the determination that providing a break-even guarantee for any investment carried out by Western Power is the most appropriate mechanism to 'promote efficient investment in the network'.

Perth Energy stands by its proposal in its initial submission that a more appropriate way to promote efficient investment in the network would be to revalue the RAB at the beginning of each Access Arrangement period and set the depreciation and return revenue amounts received in the Access Arrangement period based on the revalued asset amount, as opposed to historical cost. This would remove the guarantee Western Power currently receives with regards to its investment decisions and ensures customers are not paying more than they should with regards to network investment.

553. WAMEU

WAMEU's very concerned about the growth in the Western Power regulatory asset base (RAB) which is then multiplied by the weighted average cost of capital (WACC) to generate about half of the total costs of the services provided by WP.

… even though the draft decision opex and capex have fallen significantly and the WACC is much the same, there is an overall significant step increase in transmission revenue due primarily to the growth in the RAB. There is an increase in depreciation allowance again in part due to the massive increase in RAB. WAMEU considers that this RAB influence is due to unnecessary increases in capex allowances over the years.

WAMEU notes that while the ERA has allowed less capex than was claimed by WP, this is still more than the depreciation allowed further increasing the RAB.

WAMEU comments that this same effect is noted in the distribution part of the draft decision, but not as blatantly.

> WAMEU has reviewed the allowed asset lives for the WP assets (distribution and transmission) and note that the asset lives permitted are significantly shorter than those applied by other networks in the NEM. What concerns WAMEU is that while allowing longer asset lives would reduce the depreciation amounts included in the allowed revenue, they also imply that WP "turns over" its assets faster than occurs in the NEM, meaning assets that are still used and useful are being taken out of service early and replaced with new assets.
>
> While WAMEU accepts that the ERA cannot enforce asset write downs, it can address this concern in part by limiting capex more than it has and increasing regulatory asset life allowances to ensure that there is downward pressure on the Western Power RAB.
>
> Further, the ERA can also draw attention to the very high level of the RAB and provide a view that continuing to maintain it will impose unnecessary costs on both current and future consumers, suggesting that government could direct WP to write down the RAB to reflect an optimised network.

Considerations of the ERA

554. As set out in the draft decision, it is not clear that peak demand has declined to the extent that it is possible to identify assets that no longer contribute to providing covered services, even though Western Power's forecasts suggest peak demand is expected to be flat to slightly declining over the AA4 period.

555. The Access Code and other regulatory frameworks in Australia and other jurisdictions encourage service providers to undertake efficient investment by providing a return of their investment (i.e. depreciation) in the regulated revenue stream and for the investment to be recovered over the economic life of the assets. As required under section 6.62 of the Access Code, identifying and removing redundant assets requires careful consideration of a range of factors.

556. The ERA intends to monitor asset utilisation during AA4 to inform its decision at the next access arrangement review.

557. Western Power in its initial submission proposed the inclusion of $957.2 million of transmission and $2,860.2 million of distribution new facilities investment expenditure to be added to the capital base for the AA3 period. The ERA in the draft decision determined that $951.5 million of transmission and $2,816.6 million of distribution new facilities investment met the criteria to be added to the capital base.

558. Western Power has subsequently proposed in its revised proposal that $939.2 million of transmission and $2,852.4 million of distribution expenditure meets the criteria for inclusion in the capital base for the AA3 period.

559. The ERA has reviewed Western Power's revised proposal and determined that not all of the new facilities investment proposed by Western Power in its revised proposal meets the criteria for inclusion in the capital base.

560. From the amendments set out by the ERA in the draft decision, the ERA has accepted Western Power's larger reductions for decommissioning costs and the asbestos removal provision. The ERA also accepts retaining the $0.7 million for the Medical Centre substation capital contribution as this has already been accounted for as an offset in the revenue model as noted by Western Power.

561. The ERA has not accepted Western Power's revised proposal for unplanned wood pole expenditure for the reasons set out below.

Wood Poles

562. As noted above in the section on Western Power's revised proposal, Western Power has not reduced its wood pole expenditure for unplanned replacements to remove a double count as a result of a change in accounting treatment that occurred during the AA3 period.

563. As set out in the draft decision, Western Power changed its accounting policy mid period during AA3 which increased the proportion of the replacement cost which was capitalised from around 40 per cent to 100 per cent.

564. Western Power adopted the 40/60 capital/operating expenditure split because the true cost of the unplanned replacement could not be correctly accounted for and to avoid over-inflating the value of fixed assets, it capitalised 40 per cent of each job and left the remaining 60 per cent as operating expenditure.

565. The 40/60 split between capital and operating expenditure was the method used by Western Power to account for unplanned pole replacements at the beginning of AA3.

566. At the time of determining the AA3 operating expenditure, Western Power was subject to an EnergySafety order relating to the poor state of its wood pole network. As a result of the poor state of the wood pole network, Western Power was undertaking unplanned pole replacements in AA2 and these costs would have been included in the base amount that was used to determine Western Power's operating expenditure for AA3 under the base-step-trend method.

567. As a result, Western Power was provided with operating expenditure to continue to meet the costs of unplanned pole replacements using the 40/60 split for the entire AA3 period as it was not envisaged that the accounting treatment would change mid period.

568. As outlined above, Western Power amended its accounting policy during AA3. Consequently it has capitalised 60 per cent of costs that would have been included in operating expenditure if the accounting policy had not changed during AA3. This has resulted in these costs being recovered twice from customers, firstly in the operating expenditure allowance for AA3 and then in Western Power's claimed capital expenditure for AA3. As there is no provision for an ex-post adjustment for operating expenditure, removing these costs from the capital base is the only way to ensure customers are not paying twice for the same cost.

569. As a result, the ERA, as it did in the draft decision, requires the removal of $28.9 million in costs associated with unplanned pole replacements from the new facilities investment proposed by Western Power for AA3.

Capital base at the commencement of AA4

570. The ERA calculated revised values of the capital base for the transmission and distribution networks as at 30 June 2017 in accordance with the ERA's determination under its final decision on the value of new facilities investment in the AA3 period that may be added to the capital base under section 6.51A of the Access Code.

571. The ERA's final decision on the revised capital base values is shown in Table 62 and Table 63 below.

Table 62 ERA final decision capital base as at 30 June 2017 for the transmission network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	2,816.7	2,927.7	3,161.6	3,197.5	3,135.5	2,816.7
New facilities investment	209.3	341.6	159.2	119.9	104.1	934.1
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						
Closing asset base	2,927.6	3,161.6	3,197.5	3,135.5	3,108.6	3,108.6

Table 63 ERA final decision capital base as at 30 June 2017 for the distribution network ($ million real June 2017)

	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017	Total
Opening asset value	4,248.7	4,708.5	5,142.9	5,494.3	5,723.1	4,248.7
New facilities investment	678.5	671.4	618.2	498.0	357.4	2,823.5
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)				(4.3)
Closing asset base	4,708.5	5,142.9	5,493.3	5,723.1	5,798.4	5,798.4

Forecast regulated capital base for AA4

Access Code requirements

572. Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include forecast capital costs that are reasonably expected to satisfy the new facilities investment test.

Western Power's initial proposal

573. Table 64 and Table 65 (below) set out Western Power's initial proposed forecast capital base for AA4.

Table 64 Western Power's initial proposed forecast transmission capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening asset value	3,131.8	3,183.9	3,277.4	3,396.1	3,473.8
New facilities investment	165.8	210.7	245.6	216.0	212.7
Depreciation	113.7	117.2	126.8	138.2	144.3
Closing asset base	3,183.9	3,277.4	3,396.1	3,473.8	3,542.2

Table 65 Western Power's initial proposed forecast distribution capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening asset value	5,834.9	6,080.8	6,320.0	6,582.2	6,715.3
New facilities investment	509.5	520.0	557.4	431.3	445.7
Depreciation	263.6	280.8	295.2	298.3	289.1
Closing asset base	6,080.8	6,320.0	6,582.2	6,715.3	6,871.8

574. Table 66, Table 67 and Table 68 (below) set out Western Power's initial proposed forecast capital expenditure by regulatory category for AA4. The tables include direct costs, indirect costs and labour escalation. They exclude gifted assets and cash contributions.

575. Corporate capital expenditure is allocated across transmission and distribution with 30 per cent allocated to transmission and 70 per cent allocated to distribution. For information, a summary of total corporate capital expenditure and the allocation to each service is shown in Table 68.

Table 66 Western Power AA4 initial proposed transmission network capital expenditure ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA3 Actual	AA3 F/cast
Growth	40.6	40.9	55.4	82.4	72.1	291.4	517.2	1,154.2
Asset replacement and renewal	42.5	70.5	56.9	57.9	68.5	296.2	186.3	184.1
Improvement in service	14.0	23.6	27.0	24.7	19.1	108.4	60.3	84.3
Compliance	39.4	40.4	40.5	33.2	33.3	186.9	111.9	135.6
Corporate	29.2	35.2	65.8	17.8	19.7	167.6	81.6	125.8
Total added to the capital base	**165.8**	**210.7**	**245.6**	**216.0**	**212.7**	**1,050.6**	**957.2**	**1,683.8**

Table 67 Western Power AA4 initial proposed distribution network capital expenditure ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA3 Actual	AA3 F/cast
Growth	104.2	101.2	92.5	93.4	98.9	490.3	592.1	1,083.9
Asset replacement and renewal	279.2	255.9	248.7	243.3	250.2	1,277.3	1,613.0	1,579.8
Improvement in service	27.9	34.7	18.9	16.8	15.0	113.3	24.6	35.8
Compliance	27.7	43.2	41.7	34.2	34.4	181.3	460.5	567.9
Corporate	70.6	85.0	155.3	43.4	47.1	401.4	170.2	208.9
Total added to the capital base	**509.5**	**520.0**	**557.4**	**431.3**	**445.7**	**2,463.9**	**2,860.3**	**3,476.1**

Table 68 Western Power AA4 initial proposed corporate capital expenditure ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	AA3 Actual	AA3 F/cast
Total corporate expenditure	99.8	120.2	221.1	61.2	66.8	569.0	251.8	334.7
Transmission	29.2	35.2	65.8	17.8	19.7	167.6	81.6	125.8
Distribution	70.6	85.0	155.3	43.4	47.1	401.4	170.2	208.9

Western Power's revised proposal

576. Table 69 and Table 70 below set out Western Power's revised forecast capital base for AA4.

Table 69 Western Power's revised forecast transmission capital base ($ million real June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	3,113.8	3,156.9	3,264.7	3,381.9	3,424.7	3,113.8
New facilities investment	153.3	225.9	244.8	181.1	172.6	977.7
Depreciation	110.1	118.0	127.7	138.3	143.9	638.0
Closing asset base	3,156.9	3,264.7	3,381.9	3,424.7	3,453.4	3,453.4

Table 70 Western Power's revised forecast distribution capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	5,827.1	6,061.5	6,292.1	6,539.8	6,671.0	5,827.1
New facilities investment	492.8	512.2	540.4	424.6	425.1	2395.0
Depreciation	258.3	281.6	292.7	293.4	289.4	1415.5
Closing asset base	6,061.5	6,292.1	6,539.8	6,671.0	6,806.6	6,806.6

577. In its response to the draft decision, Western Power has provided further information it considers supports the inclusion of transmission growth and asset replacement, substation security, AMI and IT expenditure.

578. Western Power's revised proposed forecast capital expenditure by regulatory category, including its rationale, evidence and relevant supporting information, is presented in the ERA's considerations below.

Submissions on Western Power's proposal

579. Matters that were raised in submissions on Western Power's initial proposal relevant to the determination of the AA4 forecast capital base included:

- concerns that the forecast capital asset base continues to increase, despite flat or declining demand.
- the importance of ensuring only efficient investment is approved;
- whether moving to constrained network access should reduce the need for future investment, and the importance of ensuring investment prior to implementation takes account of it being introduced;
- ensuring Western Power has considered all non-network alternatives in its investment plans, including new technologies that will reduce demand or allow demand to be managed more effectively to minimise long term capital costs; and

- the effects of changing technologies and energy markets[63] on the network and the need to manage the effects of those changes on the network to maintain security and supply reliability.

580. Stakeholder views on Western Power's proposed advanced metering program were mixed. There was general recognition of the benefits advanced metering can provide, but concerns were raised about:

- A lack of information and consultation on the proposal.
- Whether the proposal was sufficiently robust to support the investment.
- Whether the roll out should be undertaken by Western Power or a contestable approach should be taken (as is the case in the national electricity market).
- Whether Western Power would actually proceed with the program given that it did not undertake the smart grid investment proposed in AA3.

581. Submissions on the ERA's draft decision forecast capital expenditure are incorporated into the ERA's considerations below.

Considerations of the ERA

582. Similar to the determination of the opening capital base, the ERA has considered whether Western Power's proposed forecast capital base is consistent with the requirements of the Access Code. The ERA's considerations include:

- the general method applied in calculating the capital base;
- an assessment of forecast capital expenditure for AA4 against the test in section 6.51A of the Access Code; and
- depreciation calculations and asset lives.

583. Each of these is considered below.

General method

584. Consistent with the method used to establish the opening capital base for AA4, Western Power calculated the capital base for each of the transmission and distribution networks using a roll-forward method, applied in a manner consistent with the method contemplated in the note to section 6.48 of the Access Code.

585. The roll-forward method is favoured by utility regulators throughout Australia and is mandated for electricity transmission and distribution networks of the National Electricity Market under chapters 6A and 6 of the National Electricity Rules.

586. The ERA determined in the draft decision that this method is consistent with the Access Code objective.

587. Summit Southern Cross Power's submission on the draft decision raises concerns that the roll forward method will be less justifiable in future:

> Getting the overarching objective of operating and investing in the network correct is important going forward – especially for the transmission network. The SWIN faces a

[63] Including battery storage systems, micro-grids, distributed generation systems, electric vehicles and the retirement of fossil fuelled generators.

> structural reorientation. The baseload generation in Collie and Kwinana is relatively swiftly being displaced by lower-cost renewable energy generation. Where transmission was previously built to accommodate the fuel located in the Collie coalfields, it will need to be reconstructed to utilise the large renewable resources north (and east) of Perth.
>
> But the reconfiguring of the transmission grid will need to occur within a declining demand paradigm. Who pays for the new investment? And should existing investment continue to earn returns and be depreciated, even as the utilisation of those assets declines?
>
> Certainly, the current measure of the asset base, by rolling forward the existing capital base, will become less justifiable going forward. This spreads the returns of both the existing network, servicing the less utilised generation being displaced, as well as the new network, required to meet changing generation sources, over a lower demand base. It would appear that an Optimised Deprival Value methodology for setting the asset base may be more appropriate, where previous but now under-utilised investments are devalued over time.

588. The ERA agrees it may be necessary to reconsider the establishment of the opening capital base in future reviews, but at this time considers the roll forward method is still consistent with the Access Code objective.

Forecast capital base for AA4

Application of the section 6.51A test to forecast new facilities investment

589. Section 6.51 of the Access Code provides for the target revenue for an access arrangement period to include capital costs calculated for an amount of forecast new facilities investment that is reasonably expected to satisfy the test in section 6.51A of the Access Code.

590. Western Power determined amounts of forecast capital expenditure to be notionally added to the capital base by deriving a total amount of forecast capital expenditure and subtracting a forecast of capital contributions.

591. The approach taken by the ERA to assess whether the forecast capital expenditure satisfies the new facilities investment test is to:

- assess whether the forecast capital expenditure is reasonably expected to satisfy the efficiency test under section 6.52(a) of the Access Code; and
- assess whether Western Power has made a reasonable forecast of the amount of capital expenditure that would satisfy the new facilities investment in its entirety.

592. The ERA's consultant GHD provided advice to assist the ERA in its review. GHD's initial review included an assessment of Western Power's governance processes, asset management strategies and forecasts.

593. GHD advised that Western Power's governance policies and processes and procedures provided a good basis for governance of investment decisions and project delivery, and that Western Power addressed 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.

594. GHD advised that Western Power invested in various parts of the business to improve weaknesses identified during the AA3 governance review. This included

poor data on asset condition and the lack of a quantitative risk assessment tool. Western Power addressed both these issues. Investment in Western Power's asset management framework led to strengthened asset condition data and Western Power developed a network risk management tool.

595. GHD's review of Western Power's asset management strategies included an assessment of:

- the level of maturity and effective integration of asset management practices in the business;
- the effectiveness of how data, information and business processes lead to sound decision making to balance risk, service levels and costs and how well these decisions aligned with the business objectives and customer needs; and
- the asset strategies for capital renewal and compliance projects and maintenance expenditure requirements which underpinned the 10-year forecast capital and operating budgets and the revenue requirements for the AA4 period.

596. GHD advised 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.

597. GHD assessed the information and business process tools and systems developed for asset management as being effective in improving asset strategies and managing risks for network assets. It noted that Western Power recognised improvement requirements in the accuracy of the data, but there were also improvements that could be made in the application of the tools to the different classes of assets.

598. GHD considered the asset management practices adopted by Western Power to be industry-leading and that asset strategies are being improved to target the higher-risk segments of each asset class. It considered the challenge for Western Power was to improve data accuracy and consistency and tools and practices to enable it to efficiently analyse and revise strategies to inform asset management decisions.

599. GHD's assessment was consistent with the results of *Western Power's 2017 Asset Management System Review* undertaken by CutlerMerz. The review findings included:

- The maturity of Western Power's Asset Management System had strengthened significantly over the review period, particularly in the area of defining strategy and objectives and enhancing the sophistication of approaches and supporting tools.
- There were comprehensive and rigorous processes in place for business as usual planning, resulting in effective asset management plans.
- Operational activities and programme delivery was systematically managed and monitored to enable desired outcomes to be achieved.
- Western Power's approach to risk based asset management could be considered effective, particularly as applied to asset maintenance and renewal.

600. Based on an assessment of the information provided by Western Power and GHD, Western Power's governance processes and asset management strategies were

assessed as generally adequate to ensure its capital expenditure forecasts could reasonably be expected to satisfy the new facilities investment test.

601. However, GHD's review of the capital expenditure forecasts identified areas of expenditure that were not reasonably expected to satisfy the new facilities investment test.

602. In making its assessment of the level of expenditure for AA4 likely to meet the requirements of the new facilities investment test, the ERA has considered the level of historical expenditure, information provided by Western Power and advice from GHD.

603. In the draft decision the ERA determined some of Western Power's forecast expenditure was not likely to satisfy the new facilities investment test. In addition, in some areas further evidence was needed to demonstrate the forecast expenditure was likely to satisfy the new facilities investment test.

604. In its response to the draft decision, Western Power has provided further information it considers supports the inclusion of transmission growth and asset replacement, substation security, AMI and IT expenditure.

605. Summit Southern Cross Power's submission on the draft decision raises concerns about assessing the efficiency of new investments.

> Assessing the efficiency of new investments is problematic. Network, and particularly transmission investments are very long-lived. An efficient investment today may not be so in the future – and vice versa. Companies in competitive environments will often reassess the book value of assets according to changing market dynamics. Under the current access arrangement, once assets are built and assessed as efficient investment, they remain so, earning regulated returns and being depreciated for their useful lives. This might be better managed on a rolling basis, where, as in competitive markets, the assets are revalued from time to time. The Optimised Deprival Value methodology of setting an asset base could again be a more appropriate mechanism in this regard.

606. In particular, Summit Southern Cross Power considers the new facilities investment test requires review.

> The current arrangements for allocating new investment to the asset base require review. Network owners should be incentivised to make efficient investment where prudent. However they should not be able to completely de-risk substantial investments before they are made. This merely transfers the risks to network users. And in the event the investments are not efficient, then transfers wealth from users to the network owner.
>
> Applying for a pre-approval of the NFIT for a substantial investment, coupled with the current interaccess arrangement roll forward method for determining the asset base, de-risks the investment. The network owner places the onus on the ERA to determine whether the investment is efficient or not. The ERA typically relies on ex-ante forecasts, produced by Western Power, that are likely to be favourable to the project. They also come under pressure from invested stakeholders, often including the government of the day, when assessing the investment. The ERA is not well placed to manage this risk assessment. The technically and commercially competent network owner is better placed to assess the likelihood of making returns on its investment.
>
> But the threat of not having the investment approved under an ex-post NFIT, and the investment not added to the asset base, makes the stakes high. This is a risk common to competitive markets (where book values can vary with market dynamics), and should be borne by a prudent network operator earning an adequate regulated return

on equity. But it likely promotes conservatism, which could lead to under-investment, which can be just as inefficient as over-investment.

Introducing a mechanism for a more dynamic assessment of investment efficiency (or assessing the book value of the network on a regular basis) might eliminate this binary decision around whether investment is deemed efficient or not. This could produce a return profile to the network operator more in line with one it might experience were it subject to competition and other market forces.

607. Summit Southern Cross Power considers the MidWest Energy Project is a prime example of the difficulty in making long-term efficient investment with the certainty of receiving a return on that investment. In particular, it considers there were two aspects that could result in risks being inappropriately transferred to existing users:

- The assessment of incremental revenue that should be taken into account in the new facilities investment test.
- The allocation of net benefits.

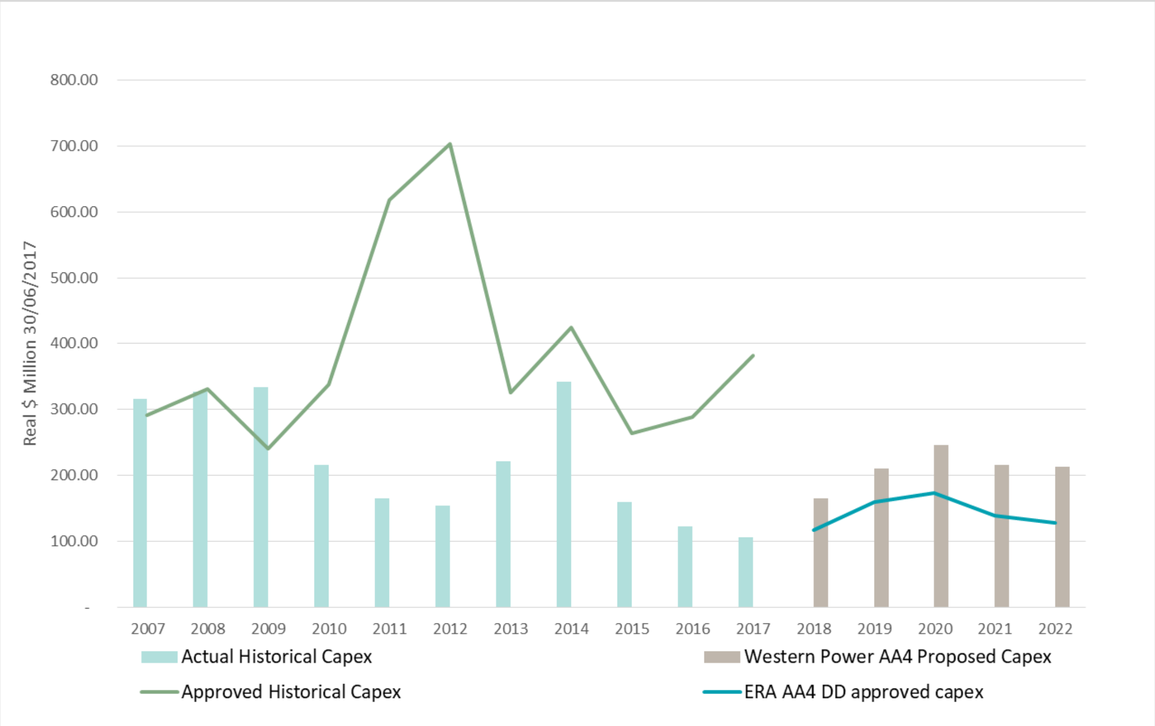
608. The ERA agrees there are improvements that can be made to ensure the investment tests, including the new facilities investment test pre-approval process, in the Access Code ensure efficient investment. However, the ERA must follow the current requirements in the Access Code and has based its AA4 assessment on those requirements.

609. The ERA has addressed the forecast capital expenditure for transmission, distribution and corporate services separately below.

Transmission forecast capital expenditure

610. Figure 10 below compares actual and forecast transmission capital expenditure since AA1 and the ERA's draft decision for AA4.

Figure 10 Comparison of historical and forecast transmission net capital expenditure



611. As can be seen above, transmission expenditure has varied from year to year and, since AA1, has been less than forecast. These differences were primarily due to peak demand increases being less than forecast and the deferral or cancellation of planned investment. The higher levels of actual expenditure in 2012/13 to 2014/15 were due to the Mid-West energy project which incurred around $400 million over that period.

612. A comparison of expenditure by regulatory category, as set out in Table 71 below, shows the largest difference between forecast and actual expenditure for AA3 is in the growth category. The under-spend of $637 million makes up 88 per cent of the total underspend.

613. Table 71 summarises Western Power's revised proposal and the ERA's final decision.

Table 71 Comparison of transmission network capital expenditure forecasts and actuals ($ million real June 2017) excluding gifted assets and cash contributions

	AA4 final decision	AA4 Western Power revised proposal	AA4 draft decision	AA4 Western Power Initial Proposal	AA3 Actual	AA3 Forecast
Growth	106.2	251.5	196.8	291.4	517.2	1,154.2
Asset replacement and renewal	247.0	283.8	161.8	296.2	186.3	184.1
Improvement in service	72.8	110.2	110.7	108.4	60.3	84.3
Compliance	168.5	180.1	117.4	186.9	111.9	135.6
Corporate	128.1	151.9	132.9	167.6	81.6	125.8
Total	**722.6**	**977.7**	**719.5**	**1,050.6**	**957.2**	**1,683.8**

614. Western Power's initial proposal for AA4 was greater than actual expenditure in AA3 due to:

- an increase in expenditure for the replacement of switchboards, static VAR compensators and protection systems;
- replacement of SCADA and communications network assets; and
- a program to increase substation security.

615. Corporate capital expenditure is discussed separately below.

616. The ERA's draft decision amendments included:

- The removal of growth projects that are unlikely to proceed in AA4 (CBD substation and Picton-Busselton 132 kV line);
- Reductions in replacement expenditure for power transformers, protection, switchboards, transmission primary plant and static VAR compensators; and
- Reductions in the proposed increase in substation security expenditure.

617. Table 72 below compares Western Power's revised proposal with its initial proposal and the draft decision.

Table 72 Western Power AA4 revised, draft decision and initial proposed transmission network capital expenditure ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	Total Revised Proposal	Draft decision	Initial proposal
Growth	45.2	57.4	57.1	51.3	40.5	251.5	196.8	291.4
Asset replacement and renewal	37.5	66.7	60.9	54.1	64.7	283.8	161.8	296.2
Improvement in service	13.9	23.5	27.4	25.4	19.8	110.3	110.7	108.4
Compliance	28.2	41.9	40.7	34.2	34.9	180.1	117.4	186.9
Corporate	28.4	36.3	58.6	15.9	12.6	151.9	132.9	167.6
Total	**153.3**	**225.9**	**244.8**	**181.3**	**172.6**	**977.6**	**719.5**	**1,050.6**

618. Capital expenditure (as shown in the tables above) includes direct costs, indirect costs and labour escalation. The considerations of specific elements of Western Power's forecast capital expenditure examined below are based on direct costs only.

619. Western Power's initial and revised forecast transmission direct costs capital expenditure for AA4 is provided in Table 73 below.

Table 73 Western Power AA4 initial and revised proposed transmission network capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	Total Revised Proposal	Draft decision	Initial proposal
Growth	37.5	48.1	47.5	40.7	31.8	205.5	159.4	240.8
Asset replacement and renewal	31.0	55.9	50.6	42.9	50.7	231.2	131.2	245.2
Improvement in service	11.5	19.7	22.8	20.2	15.6	89.9	89.9	89.9
Compliance	23.4	35.2	33.9	27.1	27.4	147.0	95.3	155.0
Corporate	23.6	30.5	48.9	12.8	10.0	125.8	109.1	143.5
Total direct capital expenditure	127.0	189.4	203.7	143.8	135.5	799.4	585.1	874.4

620. Each regulatory category for forecast transmission capital expenditure is considered below.

Transmission - growth

621. Western Power's initial proposed transmission growth capital expenditure direct costs is set out in Table 74 below.

Table 74 Western Power's AA4 initial proposed transmission growth capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Capacity expansion	25.4	26.0	38.6	59.3	50.6	199.8
Customer driven	8.2	8.2	8.2	8.2	8.2	41.0
Total Growth	**33.6**	**34.2**	**46.8**	**67.5**	**58.8**	**240.8**

622. In its initial proposal, Western Power stated its proposed growth expenditure was based on the 2016 demand forecast as there was insufficient time to take into account the most recent 2017 demand forecast before submitting its proposal. It also stated it did not have time to fully consider the effect of the retirement of the Muja AB, Western Kalgoorlie and Mungarra generators on security of supply and network reliability.

623. Western Power proposed to provide updated forecasts following the draft decision to take into account the latest demand forecast and generator retirements.

624. The ERA planned to consider this new information in its final decision to determine the level of growth expenditure likely to meet the requirements of the new facilities investment test.

625. In the draft decision, the ERA required the expenditure for two projects that were unlikely to proceed in AA4 to be removed from the forecast expenditure:

- CBD new substation –$62.2 million
- Picton-Busselton 132 kV line –$19.2 million

626. As discussed above, actual growth expenditure has generally been less than forecast resulting in adjustments to target revenue in the following period through the investment adjustment mechanism. The ERA's draft decision stated that the 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.

627. The ERA also required Western Power to provide evidence that it had considered all non-network alternatives when developing its growth investment plans.

628. The ERA's draft decision on transmission growth expenditure is set out in Table 75 below.

Table 75 ERA draft decision transmission growth capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Expenditure proposed by Western Power	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

629. In its revised proposal, Western Power has removed the CBD substation expenditure as required by the draft decision. It has not removed the Picton-Busselton 132 kV line expenditure and it has increased customer driven expenditure by $26.9 million. Western Power's revised forecast transmission growth expenditure is set out in Table 76 below.

Table 76 Western Power AA4 revised proposed transmission growth capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	Total revised proposal	Draft decision	Initial proposal
Capacity expansion	25.1	25.7	32.2	31.7	22.9	137.6	118.4	199.8
Customer driven	12.3	22.4	15.2	9.0	8.9	67.9	41.0	41.0
Total Growth	**37.5**	**48.1**	**47.5**	**40.7**	**31.8**	**205.5**	**159.4**	**240.8**

630. Western Power submits it has revised its AA4 forecast capital expenditure transmission forecasts using 2017 demand and customer numbers. Western Power states that this has resulted in limited change to the overall transmission growth expenditure forecast.

631. Western Power states that the Western Kalgoorlie and Mungarra generator retirements have not progressed significantly. As a result, transmission growth capital expenditure forecasts have not been revised to accommodate any new facilities investment required due to these generator retirements.

632. Western Power has forecast that transmission customer driven work will increase from the initially proposed $41 million to $67.9 million for the AA4 period. Western Power attributes this $26.9 million increase to:[64]

- the introduction of a Generator Interim Access (GIA) solution;

[64] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 68, para. 408.

- 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; and
- State Government investment in infrastructure projects such as Metronet.

633. The ERA has not approved the increased expenditure as Western Power has not demonstrated it is reasonably likely to meet the new facilities investment test.

634. Western Power has removed $62.2 million from forecast transmission capacity expansion capital expenditure for the CBD substation as required by the ERA. However, Western Power maintains that, based on technical and financial analysis that has been undertaken, the $19.2 million forecast capital expenditure for the Picton-Busselton 132 kV line is sufficiently justified and should be included in the AA4 forecast RAB.[65]

635. The ERA's technical consultant's review of Western Power's revised proposal for the Picton-Busselton 132 kV line indicates that the project as described in the revised proposal is very different from the original proposal. In particular, GBA notes that the revised proposal has a much larger asset replacement component.[66]

636. GBA advises that it is not satisfied that the range of options considered in Western Power's Works Planning Report included all the options available. Particularly, the long-term need for a third circuit between Picton and Busselton and the possibility of splitting the existing four-way 132 kV line into separate Pinjarra-Kemerton and Kemerton-Picton-Busselton circuits had not been considered.

637. In addition, GBA states that it is possible that the most cost-effective development plan could involve more expenditure in AA4 than currently allocated, and less in subsequent periods. This can be accommodated by the Investment Adjustment Mechanism (IAM).

638. GBA also queries whether this capital expenditure should be subject to a regulatory test under the provisions of the Code as it appears to form part of a larger group of projects that, combined, would exceed the regulatory test threshold.[67]

639. As stated in the draft decision, the ERA considers only growth projects that are reasonably likely to proceed should be approved to minimise the likelihood of under-expenditure against forecast. The Picton-Busselton 132 kV line project is currently in the scoping stage and does not have a business plan. As indicated in GBA's review, further work is needed to develop the project and evaluate all the options.

640. To ensure only growth projects that are reasonably likely to proceed are included in forecast expenditure, the ERA has only included those with a business plan. Projects in the initiation and scoping stage have not been included in the approved capital expenditure. In the event that any of these projects are undertaken during

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65 Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 73, para. 438.

66 Geoff Brown & Associates, *Review of proposed AA4 expenditure on Picton-Busselton 132kV line*, 19 September 2018, p. 3.

67 Before a service provider commits to a major augmentation ($30 million CPI adjusted) it must satisfy the regulatory test. A service provided must not disaggregate the investment for the purposes of being below the threshold.

AA4, the investment adjustment mechanism will ensure that Western Power's target revenue is adjusted at the next review for any return on the expenditure during AA4.

641. The ERA's final decision on transmission growth expenditure is set out in Table 77 below.

Table 77 ERA final decision transmission growth capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Capacity Expansion	21.0	18.7	2.3	2.7	0.3	44.8
Customer Driven	8.2	8.2	8.2	8.2	8.2	41.0
Final decision	**29.2**	**26.9**	**10.5**	**10.9**	**8.5**	**85.8**

Transmission - asset replacement and renewal

642. Western Power's initial proposed forecast transmission asset replacement and renewal expenditure is set out in Table 78 below.

Table 78 Western Power AA4 initial proposed transmission asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
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
Protection-replacement	9.3	7.8	7.7	7.7	7.7	40.3
Static VAR compensator	7.5	11.5	1.8	7.5	7.9	36.2
Primary plant	8.1	10.2	12.3	8.2	8.0	46.8
Replacement other	0.7	0.5	0.5	0.5	0.1	2.2
Total	**35.1**	**58.9**	**48.0**	**47.4**	**55.8**	**245.2**

643. Western Power initially proposed a $100 million increase in asset replacement expenditure compared to AA3 actual expenditure. Western Power submitted that its AA3 program was affected by the Muja transformer failures which resulted in planned asset replacements being deferred.

644. GHD's initial review of Western Power's planned asset replacement expenditure indicated a general lack of robustness in the forecast expenditure including:

- the proposed expenditure for power transformers was not supported by detailed investment business cases and condition reports to confirm all of the plant needs to be replaced at this time;

- information on justification of primary plant replacement was not detailed and should reflect efficiencies from the business transformation program.

645. GHD recommended the removal of the following expenditure:
    - $20.5 million for power transformers;
    - $20.1 million for protection systems;
    - $30.1 million for switchboards; and
    - $7.1 million for primary plant.

646. AEMO submitted 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. However, GHD's review indicated there was no detailed condition analysis to confirm Western Power's view that the assets needed to be replaced in AA4 or any evidence of consideration of mitigation actions that could defer the replacement.

647. The information to support the proposed costs also lacked detail and GHD considered the costs appeared excessive compared with market cost information.

648. The weaknesses identified in Western Power's expenditure forecasts resulted in the ERA being unable to conclude that the proposed expenditure was reasonably likely to meet the new facilities investment test. The ERA also noted GHD's views that some of the expenditure could be deferred to future periods. Given this is an area where planned investment has been deferred in the past, the ERA was particularly concerned that only projects that are reasonably likely to proceed during AA4 were included in the forecast expenditure.

649. The ERA's draft decision on transmission asset replacement and renewal expenditure is set out in Table 79 below. The ERA required Western Power to take account of the concerns raised regarding its asset replacement expenditure forecast and provide updated information to demonstrate its proposed expenditure is likely to satisfy the new facilities investment test and that it is reasonably likely to proceed in the AA4 period.

Table 79 ERA draft decision transmission asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Total proposed by Western Power	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

650. Western Power's revised forecast transmission asset replacement and renewal expenditure is set out in Table 80 below.

Table 80 Western Power AA4 revised proposed transmission asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Draft Decision	Initial Proposal
Primary plant	8.1	10.2	12.3	8.2	8.0	46.8	39.7	46.8
Switchboards	5.5	14.7	12.9	14.2	20.1	67.4	37.3	67.4
Power transformer	4.1	14.2	12.8	9.3	12.0	52.4	31.9	52.4
Protection – replacement	9.3	7.8	7.7	7.7	7.7	40.3	20.1	40.3
Static VAR compensator	3.4	8.6	4.4	3.0	2.9	22.2	0.0	36.2
Replacement other	0.7	0.5	0.5	0.5	0.1	2.2	2.2	2.2
Total	**31.0**	**55.9**	**50.6**	**42.9**	**50.7**	**231.2**	**131.2**	**245.3**

651. In response to the draft decision, Western Power has amended its proposed expenditure for the static VAR compensators and provided additional information to support its proposed expenditure for switchboards, power transformers, protection equipment and primary plant.

652. The ERA's technical consultant was asked to review the new material provided by Western Power and provide advice on whether the proposed expenditure was reasonably likely to satisfy the new facilities investment test.

653. GHD's original recommendation to reduce protection equipment expenditure was because it was a step change from the AA3 level of expenditure and was not adequately substantiated. Western Power has still not provided sufficient evidence that this work is required. GHD notes the existing protection schemes have been reliable to date and there is no suggestion that reliability will decline in the short term. Consequently, GHD maintains its recommendation to reduce Western Power's proposed expenditure by $20.1 million.

654. GHD's original recommendation to reduce switchboard expenditure was based on implied unit rates calculated from total expenditure and estimated numbers of switchboards to be replaced.

655. In response to the draft decision, Western Power provided more detailed information which corrected the number of switchboards to be replaced and enabled GHD to recalculate the unit rates. Based on this new analysis, GHD is satisfied the unit rates are reasonable, except for the rates used for replacement of Yorkshire/GEC switchboards at Hay Street and Milligan Street. GHD recommends reducing Western Power's proposed expenditure by $6.5 million.

656. GHD's original recommendation on transmission primary plant was that it should be reduced as a result of efficiencies through the business transformation project and greater efficiency in delivery. It notes Western Power suggested the AA4 unit rates were based on AA3 actual costs that had efficiencies embedded in them. GHD advises Western Power has not provided any additional information that would change its recommendation to reduce the proposed expenditure by $7 million.

657. GHD's original analysis of power transformers was based on incomplete information as business cases and condition reports were not available. In response to the draft decision, Western Power has provided more detailed information including business plans and condition reports. GHD advises the scope of work is consistent with the asset strategy for this asset type and the costs used by Western Power for its business cases reflect market values. GHD recommends approving the total proposed expenditure.

658. The ERA did not include any expenditure for replacement of the West Kalgoorlie and Merredin Terminal static VAR compensators as GHD's review indicated there was no detailed condition analysis to confirm Western Power's view that the assets needed to be replaced in AA4 or any evidence of consideration of mitigation actions that could defer the replacement.

659. In its revised proposal, Western Power has removed its proposed expenditure for the Merredin Terminal as work at the Merredin Terminal Station is not scheduled to commence until 2020/21 and the replacement of this asset has been deferred to AA5.

660. Western Power has provided a full scope of works and business case to support the West Kalgoorlie static VAR. GHD has reviewed the new material and advises the replacement is necessary and the proposed expenditure is reasonable.

661. The ERA has reviewed the information provided by Western Power and taken account of the advice from GHD. The ERA's final decision on transmission asset replacement and renewal expenditure is set out in Table 81 below.

Table 81 ERA final decision transmission asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Total proposed by Western Power	31.0	55.9	50.6	42.9	50.7	231.2
Protection	(4.6)	(3.9)	(3.9)	(3.9)	(3.9)	(20.1)
Switchboards	(0.5)	(1.4)	(1.2)	(1.4)	(1.9)	(6.5)
Transmission primary plant	(1.2)	(1.5)	(1.8)	(1.2)	(1.2)	(7.0)
Final decision	**24.7**	**49.1**	**43.7**	**36.4**	**43.7**	**197.6**

Transmission - improvement in service

662. Western Power's initial forecast transmission improvement in service expenditure is set out in Table 82 below.

Table 82 Western Power AA4 initial proposed transmission improvement in service capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Reliability driven	-	-	-	-	-	-
SCADA and communications						
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
Master station	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	**11.5**	**19.7**	**22.8**	**20.2**	**15.6**	**89.9**

663. Western Power noted in its proposal that in previous regulatory periods, the SCADA and communications network had been maintained on a reactive basis, and had now reached a point where technical obsolescence has become an issue and an increase in investment is required to replace obsolete SCADA and communications equipment and maintain the performance of system monitoring and control.

664. GHD advised 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.

665. GHD also noted and made the following recommendation:

> 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 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.

666. The current assets are old and in many cases no longer supported by the vendor. Reliable SCADA and communications are necessary to enable Western Power to effectively manage its network.

667. However, the ERA was concerned the forecast investment was not supported by sufficient information to demonstrate the proposed costs were likely to meet the new facilities investment test and evidence that the replacement is reasonably likely to occur in the AA4 period.

668. The ERA did not adjust the forecast expenditure for the draft decision, but required Western Power to provide sufficient information to demonstrate the costs are

reasonably likely to meet the new facilities investment test and are reasonably likely to occur in the AA4 period.

669. In its revised proposal, Western Power has proposed the same level of expenditure as initially proposed.

670. Having reviewed Western Power's supporting evidence for the deliverability of SCADA and communications expenditure, GHD considers that Western Power has not provided sufficient information to demonstrate the program will be delivered during AA4.

671. The ERA accepts there is a need to upgrade the SCADA assets but is not satisfied that Western Power has demonstrated the replacement is reasonably likely to occur in the AA4 period. The ERA has approved a level of expenditure in line with the AA3 actual expenditure as a more realistic estimate of the level of expenditure Western Power will be able to deliver during AA4.

672. The ERA's final decision on transmission improvement in service expenditure is set out in Table 83 below.

Table 83 ERA final decision transmission improvement in service capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power proposed expenditure	11.5	19.7	22.8	20.2	15.6	89.9
Reliability driven	-	-	-	-	-	-
SCADA and communications						
Asset replacement	(2.9)	(3.8)	(3.7)	(3.9)	(4.2)	(18.5)
Compliance	(0.1)	(0.7)	(1.5)	(1.3)	(1.1)	(4.6)
Corporate	(0.6)	(1.1)	(1.1)	(0.3)	(0.1)	(3.3)
Master station	(0.4)	(1.3)	(1.7)	(1.6)	(0.0)	(5.1)
Third party actions	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)
Final decision	**7.5**	**12.8**	**14.8**	**13.1**	**10.1**	**58.3**

Transmission - compliance

673. Western Power's initial proposed transmission compliance expenditure is set out in Table 84 below.

Table 84 Western Power initial proposed transmission compliance capital expenditure ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Poles and towers	12.6	12.6	12.7	11.2	11.1	60.0
Cross arm replacement	1.0	0.9	0.9	0.9	0.9	4.8
Substation security	18.2	13.2	17.1	12.4	11.3	72.1
Transformers	0.4	5.2	3.5	2.5	1.1	12.7
Protection	0.5	1.8	-	-	-	2.3
Cables			0.1	0.2	2.7	3.0
Total	**32.6**	**33.7**	**34.2**	**27.2**	**27.2**	**155.0**

674. Western Power initially proposed capital expenditure of $72.1 million for substation security. This was $66.6 million higher than expenditure during AA3. The increase in expenditure arose from Western Power's view that it had to upgrade security for all substations in its network to comply with the National Guidelines for Protecting Critical Infrastructure from Terrorism, introduced in 2015.

675. Western Power commissioned AECOM to undertake a review in 2015 to:

> … assess its assets in regard to these guidelines as well as overall safety. A full risk analysis of each substation was conducted, and a detailed program of [re]mediation requirements for each substation has been established.

676. Western Power stated that the expenditure it proposed for AA4 was to:

> … deter and detect unauthorised access to the general public and unqualified staff. Unauthorised entry can present safety risks as well as risks of damage to equipment within the substation, which may impact upon reliability of supply. The expenditure is also required to upgrade the substation buildings and grounds and prevent damage to primary and secondary equipment from damage from building failure.
>
> The project covers all aspects of substation security from physical barriers (fencing, locks), signage, lighting and active security monitoring. Western Power has determined the specific work required for each site on the basis of vulnerability assessment, condition assessment, maintenance cost history and unauthorised access incident history.

677. The ERA reviewed the material submitted by Western Power and the advice provided by its technical consultant.

678. The National Guidelines do not set any mandatory requirements on the timeline for compliance and are not prescriptive about the measures to be taken or the assets to be assessed. Individual states or businesses are left to assess this in their own risk assessment frameworks.

679. The AECOM study did not review all substations or quantify the number of incidents where unauthorised access had occurred, any costs that had actually been incurred or if there were any remote substations that had not been subject to access inside buildings or fences.

680. AECOM's study concluded that it was prudent to classify the entire SWIS as critical infrastructure. AECOM's opinion was based on a definition quoted from the Office of the Auditor General.

> … Western Australia's (WA) critical infrastructure includes those assets used in delivering power, water and transport needs that are essential to our social and economic well-being.

681. The ERA did not agree that it was the intent of the National Guidelines or the Office of the Auditor General that a blanket assessment would be applied to the whole of the SWIS.

682. Unless there is a directive or legislation from the Western Australian Government requiring all assets in the SWIS to be regarded as critical infrastructure, the ERA considered there should be a specific risk assessment for each substation.

683. For that reason, the ERA considered Western Power had not demonstrated its proposed increase in substation security was reasonably likely to meet the new facilities investment test. For the purposes of the draft decision, the ERA reduced expenditure to historical levels and required Western Power to review the requirements of the National Guidelines to develop an investment proposal based on a specific risk assessment for each substation.

684. GHD's review of the other elements of the compliance program indicated that they were based on reasonable forecasts and assumptions. Taking this advice into account, and noting the expenditure is in line with actual expenditure during AA3, the ERA considered the proposed forecast was reasonably likely to meet the requirements of the new facilities investment test.

685. The ERA's draft decision on transmission compliance expenditure is set out in Table 85 below.

Table 85 ERA draft decision transmission compliance capital expenditure ($ million real June 2017) excluding Gifted Assets and Cash Contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power proposed expenditure	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

686. Western Power's revised forecast transmission compliance expenditure is set out in Table 86 below.

Table 86 Western Power AA4 revised proposed transmission compliance capital expenditure ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Draft Decision	Initial proposal
Poles and towers	12.6	12.6	12.7	11.2	11.1	60.0	60.0	60.0
Cross arm replacement	1.0	0.9	0.9	0.9	0.9	4.8	4.8	4.8
Substation security	8.9	14.6	16.8	12.3	11.5	64.1	12.4	72.1
Transformers	0.4	5.2	3.5	2.5	1.1	12.7	12.7	12.7
Protection	0.5	1.8	-	-	-	2.3	2.3	2.3
Cables	-	-	0.1	0.2	2.7	3.0	3.0	3.0
Total	**23.4**	**35.2**	**33.9**	**27.1**	**27.4**	**147.0**	**95.2**	**154.9**

687. Western Power submits:[68]

- The National Guidelines for Protecting Critical Infrastructure from Terrorism is not the primary driver for substation security investment.
- The substation security forecast capital expenditure is based on the outcome of a detailed risk assessment of fencing and security measures at all 155 substations on the Western Power Network.

688. Western Power has identified 72 substation locations that require physical treatments over the next decade and provided a list of the five highest priority risk substation projects. Western Power expects to address 37 sites during AA4.

689. Security systems, physical access controls and key management project are the three major components of Western Power's physical security systems investment for AA4.

690. During 2017/18 Western Power conducted roof inspections and condition assessments in order to refine its roof replacement schedule and identify any expenditure or replacement work that could be deferred. The buildings and grounds roof replacement program is expected to replace four roofs per year for 10 years based on condition assessment and maintenance cost history.[69]

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[68] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 87, para. 524-525.

[69] Western Power, Revised AA4 proposal: *Response to the ERA's draft decision*, 14 June 2018, p. 92, para. 553.

691. Western Power considers:

> ..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.[70]

692. GHD has reviewed each element of Western Power's proposed expenditure:

- fencing and security systems
- physical security systems
- building and ground works – asbestos
- building and ground works – roofing.

693. GHD advises the proposed expenditure for physical security systems and building and groundworks is adequately supported and reasonable. However, it advises the number of fences Western Power proposes to replace should be reduced to reflect only the higher priority fences identified in Western Power's risk assessment. This would reduce the proposed expenditure by $10.2 million.

694. Based on the information provided by Western Power and GHD's advice, the ERA is satisfied the proposed substation security expenditure, with the exception of $10.2 million for lower priority fences, is reasonably likely to satisfy the new facilities investment test. The ERA's final decision on transmission compliance expenditure is set out in Table 87 below.

Table 87 ERA final decision transmission compliance capital expenditure ($ million real June 2017) excluding Gifted Assets and Cash Contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power proposed expenditure	23.4	35.2	33.9	27.1	27.4	147.0
Substation security	(1.5)	(2.3)	(2.7)	(2.0)	(1.8)	(10.2)
Final decision	**21.9**	**32.9**	**31.2**	**25.1**	**25.6**	**136.8**

Transmission - total

695. A summary of the ERA's final decision on transmission total direct forecast capital expenditure is set out in Table 88 below.

[70] Ibid, p. 92.

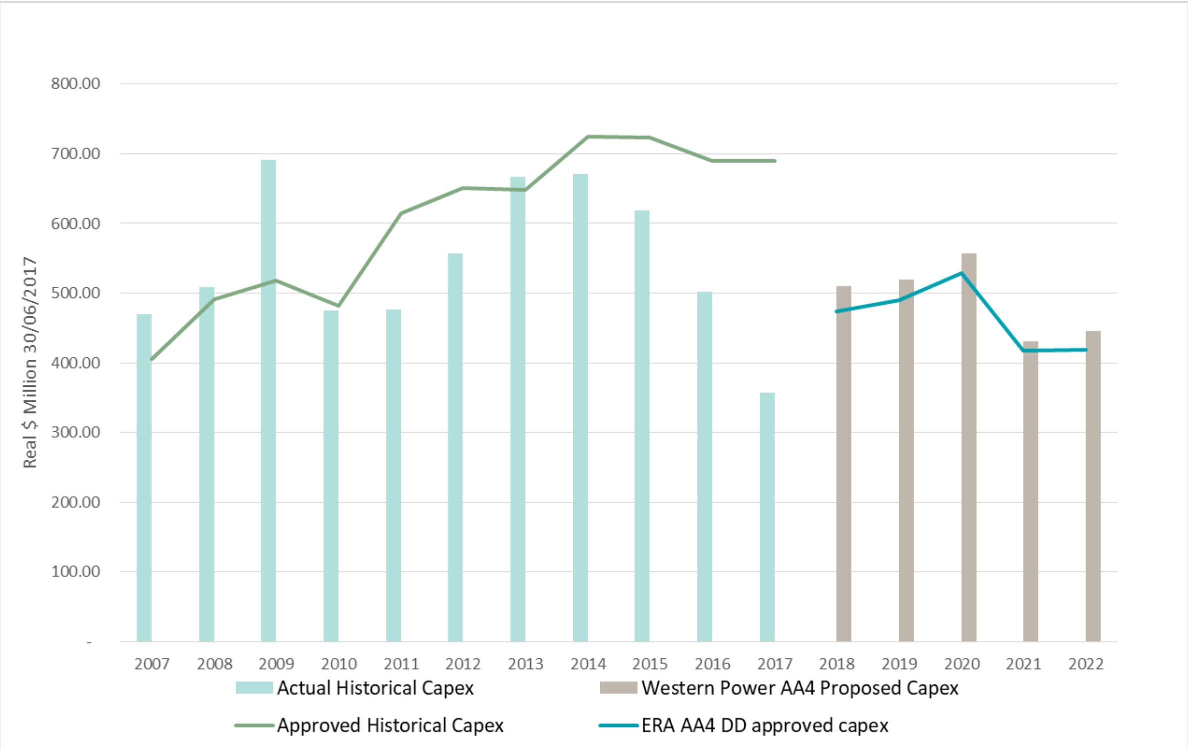
Table 88 ERA final decision transmission network capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Growth	29.2	26.9	10.5	10.9	8.5	85.8
Asset replacement and renewal	24.7	49.1	43.7	36.4	43.7	197.6
Improvement in service	7.5	12.8	14.8	13.1	10.1	58.3
Compliance	21.9	32.9	31.2	25.1	25.6	136.8
Corporate	18.2	24.7	42.9	10.3	7.9	104.0
Total direct capital expenditure	**101.5**	**146.4**	**143.1**	**95.8**	**95.8**	**582.5**

Distribution forecast capital expenditure

696. Figure 11 below compares actual and forecast distribution capital expenditure since AA1 and the ERA's draft decision for AA4.

Figure 11 Comparison of historical and forecast distribution net capital expenditure



697. As can be seen in the figure above, distribution expenditure increased during the first few years of AA3 primarily due to the wood pole program. It was lower in the final years of AA3 following completion of the EnergySafety Order in 2015 and expenditure was scaled back in 2016/17 for the business transformation program as Western Power investigated more efficient ways to deliver works.

698. A comparison of expenditure by regulatory category, set out in Table 89, below, shows the largest difference between forecast and actual expenditure for AA3 was growth, which made up 80 per cent of the total difference, and compliance, which made up 17 per cent of the total difference.

Table 89 Comparison of distribution network capital expenditure forecasts and actuals ($ million real June 2017) excluding gifted assets and cash contributions

	AA4 Final decision	AA4 Western Power revised proposal	AA4 Draft decision	AA4 Western Power initial proposal	AA3 Actual	AA3 F/cast
Growth	486.7	478.0	500.2	490.3	592.1	1,083.9
Asset replacement and renewal	1,280.1	1,274.4	1,253.7	1,277.3	1,613.0	1,579.8
Improvement in service	30.4	107.7	70.9	113.3	24.6	35.8
Compliance	186.9	183.5	184.9	181.3	460.5	567.9
Corporate	307.9	366.9	319.0	401.4	170.2	208.9
Total	**2,292.0**	**2,410.7**	**2,328.8**	**2,463.9**	**2,860.3**	**3,476.1**

699. Western Power's proposed expenditure for AA4 was lower than actual expenditure for AA3 due to lower growth expenditure from reduced demand and reductions in asset replacement and compliance expenditure due to adoption of a more risk based approach. This was offset by increases in expenditure to install advanced meters and build a communication network for those meters.

700. The ERA's draft decision adjustments included:

- reductions to conductor management unit costs;
- removal of the advanced metering communication network forecast expenditure; and
- reductions in improvements in service expenditure that were not supported by benefits.

701. Although the AA4 draft decision values for growth and compliance expenditure were shown as $9.9 million and $3.6 million greater than Western Power's proposed expenditure, this was due to the reallocation of indirect costs after other adjustments are made to operating and capital expenditure. As is discussed further below, the ERA did not make any adjustments to Western Power's proposed distribution growth or compliance direct costs in its draft decision.

702. Table 90 below compares Western Power's revised proposal with its initial proposal and the draft decision.

Table 90 AA4 revised, draft decision and initial proposed distribution network capital expenditure ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Draft decision	Initial proposal
Growth	103.8	100.7	93.6	88.3	91.7	478.0	500.2	490.3
Asset replacement and renewal	273.4	251.9	249.6	246.1	253.4	1,274.4	1,253.7	1,277.3
Improvement in service	22.7	35.4	20.4	15.7	13.5	107.7	70.9	113.3
Compliance	27.6	42.9	42.3	35.1	35.5	183.5	184.9	181.3
Corporate	69.6	88.1	138.9	39.3	31.0	366.9	319.0	401.4
Total	**497.2**	**519.1**	**544.8**	**424.6**	**425.1**	**2,410.7**	**2,328.8**	**2,463.9**

703. Western Power states that its revised AA4 distribution forecast capital expenditure has increased primarily due to additional Advanced Metering Infrastructure (AMI) expenditure.[71]

704. Consistent with transmission expenditure, the considerations below of elements of Western Power's forecast capital expenditure are based on direct costs.

705. Western Power's initial and revised forecast distribution direct costs capital expenditure for AA4 is provided in Table 91 below, broken down into regulatory categories.

[71] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 93, paragraph 558.

Table 91 Western Power AA4 revised proposed distribution capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Draft Decision	Initial proposal
Growth	86.0	84.5	78.1	70.4	72.4	391.4	405.9	405.9
Asset replacement and renewal	226.5	211.6	208.2	196.2	200.1	1,042.6	1,017.7	1,058.0
Improvement in service	18.8	29.7	17.0	12.5	10.6	88.8	57.7	94.0
Compliance	22.9	36.1	35.3	28.0	28.1	150.3	150.3	150.3
Corporate	57.8	74.0	115.8	31.4	24.5	303.6	261.8	343.6
Total direct capital expenditure	**412.0**	**436.0**	**454.4**	**338.5**	**335.7**	**1,976.7**	**1,893.3**	**2,051.8**

706. Each regulatory category for forecast distribution capital expenditure is considered below.

Distribution - growth

707. Western Power's forecast distribution growth expenditure is set out in Table 92 below.

Table 92 Western Power AA4 proposed distribution growth capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Capacity expansion	36.2	34.7	28.3	26.6	30.7	156.5
Customer driven	49.9	49.9	49.9	49.9	49.9	249.4
Total growth	**86.1**	**84.6**	**78.2**	**76.5**	**80.6**	**405.9**

708. In its initial proposal, Western Power noted that although forecast peak growth was flat, there were some parts of the network that would require reinforcement to mitigate against feeders reaching voltage limits or thermal constraints.

709. Western Power noted that the AA4 distribution capacity expansion forecast increase was driven largely by an increase in High Voltage (**HV**) distribution and HV fault rating and protection expenditure. Expenditure in these two subcategories was primarily focused on addressing increasing demand in Mandurah, Rockingham, Bunbury and Busselton, and followed a period of lower-than-expected investment.

710. As was the case for transmission growth expenditure, Western Power's initial proposal was based on the 2016 demand forecast. It proposed providing an updated expenditure forecast following the draft decision.

711. Western Power's revised forecast distribution growth expenditure is set out in Table 93 below.

Table 93 Western Power AA4 revised proposed distribution growth capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Capacity expansion	36.1	34.7	28.2	20.5	22.5	142.0
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**

712. In its revised proposal, Western Power has adjusted its growth capital expenditure to remove distribution expenditure for the CBD substation. The ERA is satisfied the forecast expenditure is reasonable and has accepted Western Power's revised proposal.

Distribution - asset replacement and renewal

713. Western Power's initial forecast distribution asset replacement and renewal expenditure is set out in Table 94 below.

Table 94 Western Power AA4 initial proposed distribution asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Conductor management	37.2	36.1	43.2	48.1	54.0	218.7
Other assets	24.2	28.7	27.3	25.6	28.4	134.1
Total asset replacement	**61.4**	**64.8**	**70.5**	**73.7**	**82.4**	**352.8**
Pole management	137.2	106.6	99.8	94.8	86.5	525.0
Metering	17.1	22.9	27.0	27.8	28.1	123.0
State Underground Power Program	14.9	19.5	12.8	3.2	6.8	57.2
Total asset replacement and renewal	**230.6**	**213.8**	**210.1**	**199.5**	**203.8**	**1,058.0**

714. The proposed asset replacement expenditure was lower than actual expenditure for AA3 reflecting Western Power's revised risk management strategy.

715. From the information provided by Western Power and GHD's advice, the ERA was satisfied the proposed expenditure was reasonably likely to meet the new facilities investment test with two exceptions:

- unit costs for conductor management; and
- the advanced metering business case.

716. GHD noted that Western Power's proposed weighted average unit cost estimate for the conductor management program was approximately $100,000 per km. However, GHD advised that a significant portion of older (and poorer condition) overhead distribution conductors are of low voltage and single phase single wire earth return types which would be at the lower end of the range used to estimate costs. GHD considered the average rate was to be reduced to $96,000 per km.

717. This adjustment to conductor unit rates was necessary to ensure the proposed expenditure was reasonably likely to meet the new facilities investment test. Consequently, the conductor management program expenditure was to be reduced from $352.8 million to $344.1 million.

718. Western Power's advanced metering proposal was based on installing 355,493 new and replacement meters over the next five years at a total cost of $177 million. This included $137 million for advanced meters with communication capability and $40 million for communication infrastructure (comprising $25.1 million in corporate SCADA and communications and $15 million in IT business-driven expenditure.)

719. 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. However, expenditure for the communications network would need to be supported by a corresponding benefit to consumers to meet the requirements of the new facilities investment test. The ERA considered the metering costs and communication costs separately below.

720. As stated above, expenditure to install advanced meters in new properties and replacement meters is reasonably likely to meet the requirements of the new facilities test. However, Western Power's forecast overestimated the number of new and replacement meters for the AA4 period. The ERA adjusted the number of meters 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 requiring replacement. This adjustment reduced metering capital expenditure by $31.6 million over the AA4 period.[72]

721. As stated above, the expenditure for communication infrastructure needs to be supported by a corresponding benefit. Western Power's advanced metering proposal was based on a business case suggesting a positive net present value would be achieved by around 2026/27 based on quantified metering service and network benefits such as remote access, interval and power factor data, fault identification, power quality monitoring and deferring network augmentation.

[72] On 27 April 2018, the ERA's technical consultant, GHD, advised it had amended its forecast of new meters to be installed to 331,925. The amendment increases forecast capital expenditure by approximately $25 million. Due to time constraints, the draft decision was not updated to include this adjustment. However, the ERA has calculated the effect on target revenue to be $4.9 million, which is less than 0.1 per cent of total target revenue and noted the adjustment would be included in the final decision.

722. Western Power's initial advanced metering business case anticipated a net present value totalling $91.5 million over 15 years. It subsequently revised this downwards to $54.9 million.

723. There were some inconsistencies in data across the information provided by Western Power on its advanced metering business case which made analysis difficult. In addition, the information provided did not include sensitivity analysis of costs and benefits which should have been undertaken, particularly given the uncertainty of the benefits.

724. After reviewing the material provided by Western Power and taking account of advice from GHD, the ERA considered the benefits had been overstated and the net present value was negative.

725. Specific benefits identified as being overstated were:

- 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;
- 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.

726. The ERA considered Western Power has not demonstrated a positive net benefit for its advanced metering program, and therefore concluded that the proposed expenditure on the communication infrastructure was not reasonably likely to meet the requirements of the new facilities investment test.

727. Consequently, the ERA required the expenditure for the communication infrastructure to be removed from the forecast capital base. As set out above, this comprised $25.1 million included under improvement in service capital expenditure and $15 million included under corporate capital expenditure.

728. The ERA's draft decision on distribution asset replacement and renewal expenditure is set out in Table 95 below.

Table 95 ERA draft decision distribution asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding Gifted Assets and Cash Contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power initial proposed expenditure	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

729. Western Power's revised forecast distribution asset replacement and renewal expenditure is set out in Table 96 below.

Table 96 Western Power AA4 revised proposed distribution asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Draft decision	Initial proposal
Conductor management	35.8	34.7	41.5	46.2	51.8	210.0	210.0	210.0
Other assets	24.1	28.6	27.3	25.6	28.4	134.1	134.1	134.1
Total asset replacement	59.9	63.3	68.8	71.8	80.2	344.1		
Pole management	137.2	106.6	99.8	94.8	86.5	525.0	525.0	525.0
Metering	14.4	22.2	26.9	26.5	26.5	116.4	91.4	123.0
State Underground Power Program	15.0	19.5	12.8	3.2	6.8	57.2	57.2	57.2
Total asset replacement and renewal	**226.5**	**211.6**	**208.2**	**196.2**	**200.1**	**1,042.6**	**1,017.7**	**1,058.0**

730. The Urban Development institute of Australia (UDIA)[73], Horizon Power[74], ENA[75], Department of Treasury – Public Utilities Office (PUO)[76], AEMO[77] and Power Ledger[78] provided submissions on the draft decision in support of Western Power's AMI program. Benefits from installing AMI identified in submissions include:

- It leads to improved network planning and safety.
- It improves the identification of faults.
- It reduces costs and promotes accurate invoicing.
- It enables numerous remote metering services such as remote de-energisation and re-energisation.
- It promotes innovation such as micro-grids, Distributed Energy Resources (DER) and peer to peer trading.

731. Power Ledger submits:

> Our business model and the benefits we provide to consumers are dependent on access to close-to-real-time energy consumption data from digital smart meters (communications-enabled AMI).
>
> It is Power Ledger's view that innovative market settlement models, such as peer-to-peer trading and other distribution-level settlement opportunities require access to close-to-real-time energy consumption data to provide opportunities for consumers to participate in the energy market in a manner that is reconcilable with existing wholesale market settlement processes.
>
> …
>
> Close-to-real-time access to metering data will allow small-use customers to participate in demand-side management opportunities that are currently only accessible to large-scale consumers.
>
> Importantly, close-to-real-time access to energy meter data will present opportunities for Western Power to develop innovative consumer engagement products that assist with the achievement of power quality and reliability standards that will become increasingly difficult to achieve if DER's continue to grow in popularity.

732. Other stakeholders such as Perth Energy and Synergy have mixed views on the AMI Program. For example, Perth Energy argues that there is still work to be done regarding the most efficient manner in which communication investment can be carried out. Nonetheless, Perth Energy says that AMI has the ability to offer more innovative products and gives customers the power to better manage their electricity cost.[79]

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[73] UDIA, *Draft decision on proposed revisions to the access arrangement for the Western Power network*, 28 May 2018.

[74] Horizon Power, *RE: Horizon Power's support for the deployment of Advanced Metering Infrastructure (AMI) in the SWIS - Western Power Access Arrangement (AA4)*, 28 May 2018.

[75] Energy Networks Australia, *Draft Decision on Proposed Revisions to the Western Power Network Access Arrangement (2017/18 to 2021/22) – Energy Networks Australia's comments*, 14 June 2018, p. 2.

[76] Department of Treasury, *Western Power's Draft Fourth Access Arrangement*, 14 June 2018, p. 3.

[77] Australian Energy Market Operator, *Draft decision on proposed revisions to the access arrangement for the Western Power network*, 14 June 2018.

[78] Power Ledger, *Western Power Access Arrangement – Use of AMI to support transition to low-cost, low-carbon energy system*, 11 May 2018.

[79] Perth Energy, *Submission to the Economic Regulation Authority regarding ERA's Draft Decision Regarding Western Power's Access Arrangement Proposal (2018-2022)*, 30 May 2018, p. 7.

733. Synergy states that the AMI program must be provided efficiently and meet the requirements of the Code particularly the NFIT and alternative options regulatory test.[80] Synergy also states that there is no clear mechanism under AA4 for network benefits to be delivered through to the end customer and that it is important to note that the price customers are willing to pay for meters dictates their deployment.

734. WAMEU and Vector Limited (Vector) urge caution regarding Western Power's AMI program. WAMEU points out that little value has been realised from AMI programs in other jurisdictions, and further investigation should be undertaken by the ERA to demonstrate that consumers will benefit from Western Power's AMI program.[81]

735. Vector states that the AMI program must not be approved until it complies with the regulatory test in chapter nine of the Code. Vector submits that a competitive regulatory framework for metering services provides choice and better outcomes for consumers and other network users.[82]

736. Western Power's updated advanced metering business case information, has made the ERA aware that Western Power's proposed expenditure for new and replacement meters includes the cost of a communications card. In its business plan, Western Power has correctly treated this as an incremental cost for the advanced metering cost benefit analysis. As stated in the draft decision, the ERA considers that 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. However, the incremental costs to install cards for remote communications would need to be supported by a net benefit in order to meet the new facilities investment test.

737. Consequently, the ERA has adjusted Western Power's proposed metering expenditure to remove the incremental cost for communication cards. The adjustment and revised metering expenditure is set out in Table 97 below.

[80] Synergy, *Economic Regulation Authority draft decision on proposed revisions to the access arrangement for the Western Power network*, p. 60.

[81] WAMEU, *Response to the ERA Draft Decision*, May 2018, p. 49.

[82] Vector Limited, *Submission on the Draft Decision on Western Power's Proposed Revisions to its Access Arrangement - AA4*, 14 June 2018, paragraph 11.

Table 97 ERA Final decision metering capital expenditure direct costs ($ million real June 2017)

		2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power proposed metering capital expenditure	$’000	14.4	22.2	26.9	26.5	26.5	116.4
Number of meters		50,292	63,231	71,358	73,173	73,871	331,925
Incremental cost per meter[83]	$/meter	4	42	49	51	52	
Total incremental cost	$’000	(0.2)	(2.6)	(3.5)	(3.7)	(3.8)	(13.9)
Revised metering expenditure	$’000	14.2	19.5	23.4	22.7	22.7	102.5

738. In response to the ERA’s draft decision, Western Power accepts there were inconsistencies in the information it provided on its advanced metering business case in its initial proposal and during the ERA’s review for the draft decision.

739. In February 2018, Western Power presented a change control for the AMI business case to its Board of Directors. The change control, which was provided to the ERA, updates the costs to reflect a five-year view of expenditure, and incorporates revised costs following a competitive tender process for meters, the RF mesh network and the IT system requirement.[84]

740. The ERA has assessed Western Power’s revised proposal for advanced meters. The assessment has again been hampered by incomplete and inconsistent information.

741. Western Power’s revised business case includes a reduction in forecast benefits of $126.6 million ($NPV) offset by a reduction in forecast costs of $140.3 million ($NPV) resulting in a projected net benefit of $68.6 million compared with the initial business case estimate of $91.5 million.

742. GHD has changed its view from the advice it provided to the ERA for the draft decision and now considers the NPV for the project is positive.

743. GHD expresses some concern about the increase in business-as-usual metering costs of 37 per cent, with the corresponding reduction in incremental costs used in the cost benefit analysis. The ERA sought further information from Western Power to understand how it had arrived at its metering business-as-usual and incremental costs but Western Power did not provide sufficient information to demonstrate that the costs were justified.

[83] Based on Western Power’s cost benefit model.

[84] Western Power, *Revised AA4 proposal: Response to the ERA’s draft decision*, 14 June 2018, p. 102, paragraph 600 - 601.

744. GHD notes that Western Power has included indirect costs and contingencies as a benefit. GHD considers it is appropriate to allocate indirect costs and contingencies associated with avoided costs, noting that an assumption that avoided direct costs will also result in an overhead cost reduction is reasonable.

745. GHD concludes that, despite any reservations it may have about the level of costs used in the analysis and any benefits that may be overstated, if the financial value of benefits that can accrue to other users of the network (i.e. generators and retailers) were included, these would outweigh any potential understatement of costs or overstatement of benefits and the NPV would be positive.

746. The ERA considers GHD's approach has not resulted in a sufficiently robust assessment of Western Power's proposal. The ERA's review is limited to evaluating the costs and benefits used by Western Power in its cost benefit analysis. Seeking to justify the project on some possible but unassessed benefits is not sufficient for the ERA to be reasonably certain that the expenditure will satisfy the new facilities investment test.

747. The ERA also considers that contingencies and indirect costs should not be included as a benefit. Of the $68.6 million net benefit calculated by Western Power, $39.7 million is for contingencies and indirect costs.

748. The ERA has identified other discrepancies in the cost/benefit model which if adjusted would result in a negative NPV. These include:

- Incorrect WACC and CPI assumptions used in the NPV calculation.
- Forecast demand values inconsistent with the 2017 demand forecast (assuming 1.5 per cent per annum increases rather than the reductions projected in the 2017 demand forecast).
- A doubling of the benefit attributed to energy theft, which is the largest single benefit identified (from $17.9 million in the original business case to $35 million in the latest business case) with insufficient information to support such a large adjustment.

749. On that basis, the ERA considers insufficient evidence has been provided to it for it to be reasonably certain that the proposed expenditure will meet the new facilities investment.

750. The ERA acknowledges many stakeholders made submissions in support of advanced metering and the benefits it could bring.

751. One of those benefits is that advanced metering could improve safety by allowing remote fault checking. This may be the case, however the advanced metering proposal provided to the ERA only includes advanced meters for new properties, replacement meters for non-compliant meters and replacement meters requested by customers/retailers.[85] The costs of installing advanced meters for other purposes, such as to assist with fault detection, have not been included in Western Power's proposal. Based on Western Power's projected new properties and meter replacements, approximately one third of existing properties would still not have an advanced meter at the end of the 15 years considered in the cost/benefit analysis.

[85] Which must be paid for by the customer/retailer.

752. The ERA is not satisfied that Western Power has adequately demonstrated that the proposed advanced metering program is reasonably likely to meet the new facilities investment test. The ERA has approved expenditure for installing modern electronic devices with enhanced capabilities, but has not approved the additional communication infrastructure, including communication cards, proposed by Western Power.

753. Consequently, expenditure for the advanced metering communication infrastructure and communication cards must be removed from forecast capital expenditure.

754. The ERA's final decision on distribution asset replacement and renewal expenditure is set out in Table 98 below.

Table 98 ERA final decision distribution asset replacement and renewal capital expenditure direct costs ($ million real June 2017) excluding Gifted Assets and Cash Contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power proposed expenditure	**226.5**	**211.6**	**208.2**	**196.2**	**200.1**	**1,042.6**
Metering adjustment	(0.2)	(2.7)	(3.5)	(3.8)	(3.8)	(13.9)
Final decision	**226.3**	**208.9**	**204.7**	**192.5**	**196.3**	**1,028.7**

Distribution – improvement in service

755. Western Power's initial forecast distribution improvement in service expenditure is set out in Table 99 below.

Table 99 Western Power AA4 initial proposed distribution improvement in service capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Reliability-driven						
Distribution reliability other	3.0	7.7	1.5	0.5	0.5	13.1
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
Total	**4.2**	**8.9**	**2.7**	**1.7**	**1.7**	**19.2**
SCADA and communications						
Asset replacement	3.9	5.2	7.6	7.4	8.2	32.2
Core infrastructure growth	0.2					0.2
Corporate-advanced meters	10.5	10.5	1.6	1.7	1.0	25.1
Master station	4.2	4.5	4.1	3.0	1.3	17.2
Total	**18.8**	**20.1**	**13.2**	**12.1**	**10.5**	**74.8**
Total improvement in service	**23.0**	**29.0**	**16.0**	**13.8**	**12.2**	**94.0**

756. The reliability-driven expenditure included $8 million for the Kalbarri micro-grid which was supported by a business case and demonstration of benefits arising through improvements to rural long SAIDI. However, the remaining expenditure was not supported by demonstrated benefits. Consequently the ERA considered the expenditure was not reasonably likely to meet the new facilities investment test and required it to be removed.

757. Similar to transmission capital expenditure, Western Power forecast significant increases in SCADA and communications expenditure in AA4 compared to AA3. Western Power submitted the increase in distribution SCADA and communication investment was required to replace obsolete equipment and maintain the performance of network monitoring and control.

758. Consistent with its view on the proposed transmission SCADA and communications expenditure, the ERA was concerned the forecast investment was not supported by sufficient information to demonstrate the proposed costs were likely to meet the new

facilities investment test and evidence that the replacement was reasonably likely to occur in the AA4 period.

759. In the draft decision, the ERA did not adjust the forecast expenditure but required Western Power to provide sufficient information to demonstrate the costs were reasonably likely to meet the new facilities investment test and were reasonably likely to occur in the AA4 period.

760. As set out above, the ERA considered Western Power's proposed installation of a communications network for the advanced meters was not reasonably expected to meet the new facilities investment test. Consequently the proposed expenditure of $25.1 million for advanced meters was removed.

761. The ERA's draft decision on distribution improvement in service expenditure is set out in Table 100.

Table 100 ERA draft decision distribution improvement in service capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power 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	(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

762. Western Power's revised forecast distribution improvement in service expenditure is set out in Table 101 below.

Table 101 Western Power's AA4 revised proposed distribution improvement in service capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Draft decision	Initial proposal
Reliability-driven								
Distribution reliability other	2.7	7.8	0.8	0.5	0.1	11.9	8.0	13.1
Targeted reliability-driven automation	-	-	-	-	-	-	-	5.5
RD pilot projects	-	-	-	-	-	-	-	0.5
Total	**2.7**	**7.8**	**0.8**	**0.5**	**0.1**	**11.9**	**8.0**	**19.1**
SCADA and communications								
Asset replacement	3.9	5.2	7.6	7.4	8.2	32.2	32.2	32.2
Core infrastructure growth	0.2	-	-	-	-	0.2	0.2	0.2
Corporate-advanced meters	7.8	12.2	4.5	1.7	1.0	27.1	0	25.1
Master station	4.2	4.5	4.1	3.0	1.3	17.2	17.2	17.2
Total	**16.1**	**21.9**	**16.2**	**12.1**	**10.5**	**76.8**	**49.6**	**74.7**
Total improvement in service	**18.8**	**29.7**	**17.0**	**12.5**	**10.6**	**88.8**	**57.6**	**93.9**

763. The ERA approved $8 million for the Kalbarri micro-grid project as part of its draft decision. Western Power's revised proposal includes an additional $3.9 million of reliability-driven other expenditure to improve Western Power's ability to address and isolate faults.[86]

764. The ERA has reviewed the information provide to support the increased expenditure and considers only one of the proposed projects, for an emergency response

[86] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 99 - 100, paragraph 583 - 586.

generator HV connector with a value of $0.6 million, was sufficiently progressed and reasonably likely to satisfy the new facilities investment test during AA4.

765. Western Power has increased its projected costs for advanced meters. It considers the proposed $27.1 million forecast expenditure for the installation of a Radio Frequency (RF) mesh two-way communications network is the most efficient cost option for the volume of advanced meters it proposes to install in AA4.[87]

766. As discussed above, the ERA has reviewed the advanced metering business case again for the final decision and considers it is not reasonably likely to meet the new facilities investment test.

767. The ERA's final decision on distribution improvement in service expenditure is set out in Table 102 below.

Table 102 Final decision distribution improvement in service capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Western Power proposal	18.8	29.7	17.0	12.5	10.6	88.8
Reliability-driven						
Distribution reliability other	0.8	(2.8)	(0.8)	(0.5)	(0.1)	(3.4)
SCADA and communications						
Asset replacement	(2.6)	(3.5)	(5.1)	(5.0)	(5.6)	(21.8)
Core infrastructure growth	(0.1)	-	-	-	-	(0.1)
Corporate-advanced meters	(7.8)	(12.2)	(4.5)	(1.7)	(1.0)	(27.1)
Master station	(2.9)	(3.1)	(2.8)	(2.0)	(0.9)	(11.7)
Final decision	**6.3**	**8.1**	**3.8**	**3.4**	**3.1**	**24.6**

Distribution - compliance

768. Western Power's initial forecast distribution compliance expenditure is set out in Table 103 below.

Table 103 Western Power AA4 proposed distribution compliance capital expenditure direct costs ($ million June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Compliance	22.9	36.1	35.3	28.0	28.1	150.3

[87] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 100, paragraph 590.

769. Western Power's proposed compliance program was 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 was satisfied the proposed expenditure was reasonably likely to meet the requirements of the new facilities investment test.

Distribution - total

770. For the reasons outlined above, the ERA considers that not all of Western Power's proposed distribution capital expenditure is likely to meet the requirements of the new facilities investment test.

771. A summary of the ERA's final decision on the value of distribution direct capital expenditure that is reasonably likely to meet the new facilities investment test is set out in Table 104 below.

Table 104 ERA final decision distribution network capital expenditure direct costs ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Growth	86.0	84.5	78.1	70.4	72.4	391.4
Asset replacement and renewal	226.3	208.9	204.7	192.5	196.3	1028.7
Improvement in service	6.1	8.1	3.8	3.4	3.1	24.6
Compliance	22.9	36.1	35.3	28.0	28.1	150.3
Corporate	44.4	59.5	101.5	25.2	19.5	250.0
Total	**385.9**	**397.2**	**423.3**	**319.4**	**319.3**	**1,845.1**

Corporate capital expenditure

772. Table 105 below compares actual and forecast corporate capital expenditure for AA3 and AA4.

Table 105 Comparison of corporate capital expenditure forecasts and actuals ($ million real June 2017) excluding gifted assets and cash contributions

	AA4 Final Decision	AA4 Western Power revised proposal	AA4 Draft Decision	AA4 Western Power Proposal	AA3 Actual	AA3 Forecast
Total corporate expenditure	**354.1**	**518.9**	**451.9**	**569.0**	**251.8**	**334.7**
Transmission	104.0	151.9	132.9	167.6	81.6	125.8
Distribution	250.0	367.0	319.0	401.4	170.2	208.9

773. Historically, Western Power has underspent against its corporate expenditure forecasts due to the deferral of projects. Western Power stated the under-spend against forecast for AA3 was due to a delay in rebuilding some of its depots which was forecast to take place during AA3.

774. In its initial proposal, Western Power noted that the primary driver for the increase in AA4 was the need to modernise Western Power's portfolio of metropolitan and regional operational depots, many of which Western Power considered were in poor condition.

775. In addition, Western Power's initial proposal for AA4 was higher than AA3 actuals as it included:

- adding the fleet assets to the regulated capital base;
- IT business driven expenditure for advanced metering; and
- new Customer Relationship Management (CRM) software.

776. The ERA's draft decision:

- removed the fleet assets from the regulated capital base;
- removed the advanced metering expenditure; and
- removed the expenditure for the new CRM software.

777. The ERA also required Western Power to submit more evidence to demonstrate that the remaining proposed expenditure was reasonably likely to meet the new facilities investment test.

778. Table 106 below compares Western Power's revised proposal with its initial proposal and the draft decision.

Table 106 AA4 Western Power revised, draft decision and initial proposed corporate capital expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Revised proposal	Draft decision	Initial proposal
Total corporate expenditure	98.0	124.4	197.5	55.2	43.6	518.8	400.6	527.2
Transmission	28.4	36.3	58.6	15.9	12.6	151.9	81.6	125.8
Distribution	69.6	88.1	138.9	39.3	31.0	366.9	319.0	401.4

779. Consistent with transmission and distribution expenditure, the considerations below of specific elements of Western Power's forecast corporate capital expenditure are based on direct costs.

780. Western Power's initial forecast corporate direct costs capital expenditure are set out in Table 107 below.

Table 107 Western Power AA4 initial forecast corporate direct cost capital expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Business Support						
Corporate real estate	23.3	43.2	116.6	9.9	8.1	201.1
Fleet	11.8	6.1	26.9	7.6	24.7	77.2
Property plant and equipment	0.8	0.8	0.8	0.8	0.8	4.2
Total	**36.0**	**50.2**	**144.3**	**18.4**	**33.7**	**282.5**
ICT						
Business-driven	39.9	39.3	29.5	22.4	18.1	149.3
Business infrastructure	8.5	12.1	17.0	10.8	7.0	55.3
Total	**48.4**	**51.4**	**46.6**	**33.2**	**25.1**	**204.6**
Total corporate capital expenditure	**84.4**	**101.5**	**190.8**	**51.6**	**58.7**	**487.1**

781. Corporate real estate included $184 million for depot modernisation and $16 million for relocating the control centre. The expenditure was supported by business cases which GHD advised were reasonable.

782. However, the ERA considered Western Power had not adequately demonstrated the net benefits of the proposed expenditure satisfied the second limb of the new facilities investment test. For example, Western Power did not adequately demonstrate that the savings arising from modernised depots had been incorporated in forecast operating and capital expenditure.

783. Given the history of Western Power deferring this type of expenditure in the past, the ERA required evidence from Western Power that it was reasonably certain this project was going to proceed in AA4.

784. The fleet expenditure reflected a change in the way Western Power accounts for its fleet costs.

785. Historically, plant and vehicle costs have been ring-fenced, in accounting terms, from covered (regulated) services. Plant and vehicle costs are charged to regulated services operating and capital works on a usage basis ($ per hour). This results in the costs being expensed directly against the relevant works and in the case of capital works, the costs are included in the capital asset base.

786. In its initial submission, Western Power proposed to include fleet assets in the regulated capital asset base. In addition, in 2019/20 there will be a change in accounting standards requiring operating leases to be recognised as an asset (and the future payments as a liability). Western Power proposed adding the asset value arising from this accounting change to the capital asset base.

787. This change in treatment would result in fleet costs being included in depreciation and earning a return on the regulated capital asset base.

788. As discussed under forecast operating expenditure, Western Power made a step change reduction in indirect costs of $10.5 million each year from 2019/20 to reflect the change in the treatment of fleet costs.

789. The ERA considered this change in approach was inconsistent with the new facilities investment test. The regulated capital base must only include capital expenditure that meets, or is reasonably likely to meet, the new facilities investment test. Adding an amount for existing vehicles previously purchased by the unregulated business, or an amount arising from an accounting adjustment to capitalise leases is not consistent with the requirements of the new facilities investment test.

790. The current method of accounting for fleet assets in the non-regulated business and charging costs to the relevant regulated services based on usage, ensures costs are allocated between the regulated and non-regulated business. The draft decision required Western Power to maintain the current arrangements and the fleet assets, including the capitalisation of operating leases, should not be added to the regulated capital asset base.

791. Western Power's initial proposed information technology spend was $88 million higher (a 76 per cent increase) than actual AA3 expenditure. GHD advised a large part of the increase was catch-up investment on corporate systems that have been deferred over previous review periods. In addition, the IT business-driven expenditure included $15 million for advanced metering infrastructure and $24 million for new CRM software.

792. As discussed under forecast distribution capital expenditure, in the draft decision the ERA considered the advanced metering infrastructure costs were not reasonably likely to meet the new facilities investment test and therefore required it to be removed from the forecast capital expenditure.

793. GHD advised the current CRM system is over 10 years old and in need of replacement. However, it advised the forecast expenditure was excessive and there are other, less capital intensive options that could reduce the expenditure involved.

794. In the draft decision the ERA considered Western Power had not demonstrated sufficiently that its proposed CRM software was reasonably likely to meet the new facilities investment test and therefore required it to be removed from the forecast capital expenditure.

795. Similar to the proposed depot expenditure, given the history of deferrals in IT expenditure, the ERA also required Western Power to provide evidence that the proposed projects were reasonably likely to proceed and was to consider this in its final decision.

796. The ERA's draft decision on the value of corporate expenditure that was reasonably likely to meet the new facilities investment test is set out in Table 108 below.

Table 108 ERA draft decision corporate direct cost capital expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Western Power 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)
Customer relationship management 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**

797. The allocation between transmission and distribution is set out in Table 109 below.

Table 109 ERA draft decision allocation of corporate capital expenditure direct costs between transmission and distribution ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Total direct expenditure added to the capital base	57.8	88.6	158.3	38.3	28.0	370.9
Transmission	16.9	26.0	47.1	11.1	8.1	109.1
Distribution	40.9	62.6	111.2	27.2	19.8	261.8

798. Western Power's revised forecast corporate direct costs capital expenditure are set out in Table 110 below.

Table 110 Western Power AA4 revised forecast corporate direct cost capital expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4	Draft Decision	Initial proposal
Business Support								
Corporate real estate	23.3	43.2	116.6	9.9	8.1	201.1	201.1	201.1
Fleet	-	-	-	-	-	-	-	77.2
Property plant and equipment	0.8	0.8	0.8	0.8	0.8	4.2	4.2	4.2
Total	**24.2**	**44.1**	**117.4**	**10.7**	**8.9**	**205.3**	**205.3**	**282.5**
ICT								
Business-driven	48.7	48.5	30.3	22.6	18.6	168.7	110.3	149.3
Business infrastructure	8.5	12.1	17.0	10.8	7.0	55.3	55.3	55.3
Total	**57.2**	**60.5**	**47.3**	**33.4**	**25.6**	**224.1**	**165.6**	**204.6**
Total corporate capital expenditure	**81.4**	**104.6**	**164.7**	**44.2**	**34.5**	**429.4**	**370.9**	**487.1**

799. In its revised proposal, Western Power accepted the ERA's required amendment to remove fleet assets from the regulated capital base, but did not accept the removal of the expenditure for the advanced metering program or the Customer Relationship Management (CRM) software.

800. In its revised proposal, proposed costs for advanced metering infrastructure have increased from $15 million to $34.4 million based on the results of a tender. As discussed above, the ERA considers the advanced metering program is not reasonably likely to meet the new facilities investment test and must be removed from the expenditure forecasts.

801. Western Power states that its proposed CRM expenditure covers expenditure on the software itself including associated systems that will use the platform to help enhance the quality of customer service.[88]

[88] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 112, para. 668.

802. Western Power submits that the CRM system will:

- Enhance customer data analytics available to Western Power;
- Facilitate the development of a metering data portal which will provide online access to customers' interval reading data from advanced meters; and
- Reduce the number of bespoke solutions required to existing disparate systems to interface with each other.

803. Western Power considers that its proposed CRM expenditure is comparable with other distribution network businesses and represents efficient expenditure.

804. WAMEU's submission on the draft decision raises concerns regarding the level of corporate expenditure proposed by Western Power. WAMEU questions the general increase in Western Power's corporate capital expenditure:[89]

> Corporate capex is increasing both in absolute terms and relative to total capex. Capital intensive WAMEU members highlight that corporate capex should be relatively constant and not increase.

805. The ERA has not included the proposed CRM expenditure in the final decision as delivery of the program and evidence that the most efficient option has been selected has not been adequately demonstrated. On the basis that a new CRM will deliver efficiencies, the ERA considers Western Power can proceed with the project without the need for an uplift in corporate expenditure.

806. Western Power states that its depot modernisation program is a key component of Western Power's property management strategy and is expected to be delivered in full during the AA4 period. Western Power adds that it seeks to redevelop seven depots over AA4 to provide fit for purpose facilities to its personnel.[90]

807. WAMEU raises concerns about Western Power's proposed depot modernisation expenditure:[91]

> WAMEU notes that a large element of the proposed corporate capex relates to depot renewal. While WAMEU considers that capex which reduces other costs (eg opex) needs to be investigated, there is no clarity that the value of this capex to consumers delivers a larger benefit to consumers than not investing.

808. The ERA, with the assistance of GHD, has undertaken further review of Western Power's proposed depot modernisation program. Based on this review, the ERA considers it unlikely the full program will be completed in AA4. A reduction of $16.9 million has been made to reflect this. The ERA also considers the efficiencies that will arise from the modernisation program need to be included in the operating cost forecasts. Based on advice from GHD, the ERA has included savings of $10 million for AA4 and expects the efficiencies will continue to grow in AA5 as the project is completed.

809. The ERA's final decision on the value of corporate expenditure that is reasonably likely to meet the new facilities investment test is set out in Table 111 below.

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[89] WAMEU, *Response to the ERA Draft Decision*, May 2018, p. 47.

[90] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision,* 14 June 2018, p. 116, paragraph 691.

[91] WAMEU, *Response to the ERA Draft Decision*, May 2018, p. 48.

Table 111 ERA final decision corporate direct cost capital expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Western Power proposal	81.4	104.6	164.7	44.2	34.5	429.4
Depot modernisation						(16.9)
Advanced metering infrastructure						(34.4)
Customer relationship management software						(24.0)
Final decision	**62.5**	**84.2**	**144.5**	**35.4**	**27.4**	**354.0**

810. The allocation between transmission and distribution is set out in Table 112 below.

Table 112 ERA final decision allocation of corporate capital expenditure direct costs between transmission and distribution ($ million real June 2017) excluding gifted assets and cash contributions

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Total direct expenditure added to the capital base	62.5	84.2	144.5	35.4	27.4	354.0
Transmission	18.2	24.7	42.9	10.3	7.9	104.0
Distribution	44.3	59.5	101.5	25.2	19.5	250.0

Indirect costs and labour escalation

811. As discussed in the operating expenditure section, in the draft decision the ERA amended Western Power's proposed indirect costs as they were not consistent with a service provider efficiently minimising costs. In addition, the ERA's amendments to direct capital expenditure and operating expenditure affected the allocation of indirect costs and labour escalation across different categories of expenditure.

812. The indirect costs and labour escalation included in the ERA's draft decision are set out in Table 113 and Table 114 below.

Table 113 Indirect costs and labour escalation included in ERA draft decision transmission capital expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Western Power Initial Proposal
Direct capital costs approved by the ERA	95.9	132.0	144.1	111.1	102.1	585.1	874.4
Indirect cost allocation	21.4	26.8	28.1	26.1	24.0	126.4	164.0
Labour escalation allocation	0.4	1.1	1.9	2.1	2.5	8.0	12.1
Total capital expenditure	**117.7**	**159.9**	**174.0**	**139.3**	**128.6**	**719.5**	**1,050.6**

Table 114 Indirect costs and labour escalation included in ERA draft decision distribution expenditure ($ million real at June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Western Power initial Proposal
Direct capital costs approved by the ERA	385.9	404.3	437.9	332.6	332.6	1,893.3	2,051.8
Indirect cost allocation	86.3	82.2	85.3	78.2	78.2	410.2	385.4
Labour escalation allocation	1.7	3.3	5.7	6.3	8.3	25.3	26.6
Total capital expenditure	**474.0**	**489.8**	**528.9**	**417.1**	**419.0**	**2,328.8**	**2,463.9**

813. The revised indirect costs and labour escalation allocated to transmission and distribution capital expenditure in the final decision are set out in Table 115 and Table 116 below.

Table 115 Indirect costs and labour escalation included in ERA final decision transmission capital expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Western Power Revised Proposal
Direct capital costs approved by the ERA	101.5	146.4	143.1	95.8	95.8	582.5	799.7
Indirect cost allocation	22.4	29.3	28.2	23.2	22.9	126.1	156.4
Labour escalation allocation	0.3	2.0	3.8	4.0	5.4	15.6	21.6
Total capital expenditure	**124.2**	**177.6**	**175.1**	**123.2**	**124.1**	**724.3**	**977.7**

Table 116 Indirect costs and labour escalation included in ERA final decision distribution expenditure ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total	Western Power Revised Proposal
Direct capital costs approved by the ERA	385.9	397.2	423.3	319.4	319.3	1,845.1	1,976.5
Indirect cost allocation	85.6	79.7	83.6	77.6	76.3	402.9	389.6
Labour escalation allocation	1.0	4.8	10.1	11.6	15.3	42.9	44.6
Total capital expenditure	**472.5**	**481.7**	**517.1**	**408.5**	**410.9**	**2,290.7**	**2,410.7**

Summary of revised capital expenditure

814. The ERA has calculated revised values for AA4 forecast capital expenditure in accordance with the ERA's determination under the final decision on whether the forecast of new facilities investment may, under section 6.50 of the Access Code, be taken into account in the determination of total costs and target revenue. The revised values are shown in Table 117, Table 118 and Table 119 below.

Table 117 ERA final decision transmission network capital expenditure including indirect costs and labour escalation and excluding gifted assets and cash contributions ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Growth	35.7	32.7	12.8	14.0	11.0	106.2
Asset replacement and renewal	30.2	59.7	53.5	46.9	56.7	247.0
Improvement in service	9.2	15.6	18.1	16.9	13.1	72.8
Compliance	26.6	39.5	37.8	31.9	32.7	168.5
Corporate	22.2	29.9	52.6	13.1	10.2	128.1
Total added to the capital base	**123.9**	**177.3**	**174.7**	**122.8**	**123.7**	**722.4**

Table 118 ERA final decision distribution network capital expenditure including indirect costs and labour escalation and excluding gifted assets and cash contributions ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Growth	105.3	102.5	95.4	90.0	93.2	486.4
Asset replacement and renewal	277.2	253.6	249.9	246.4	252.8	1,280.0
Improvement in service	7.7	9.8	4.6	4.3	4.0	30.4
Compliance	28.1	43.8	43.1	35.8	36.1	186.9
Corporate	54.2	72.2	124.2	32.2	25.0	307.9
Total added to the capital base	**472.6**	**481.9**	**517.2**	**408.7**	**411.1**	**2,291.5**

Table 119 ERA final decision corporate capital expenditure including indirect costs and labour escalation and excluding gifted assets and cash contributions ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Total corporate expenditure	**76.4**	**102.1**	**176.6**	**45.3**	**35.2**	**435.8**
Transmission	22.2	29.9	52.5	13.1	10.2	128.0
Distribution	54.2	72.2	124.1	32.2	25.0	307.8

Depreciation

815. Under section 6.70 of the Access Code, an access arrangement must include a specification of the method by which depreciation allowances for assets of the capital

base are calculated, assumptions for asset lives and the circumstances in which the depreciation of a network asset may be accelerated.

816. Western Power's proposed method and assumptions for calculation of depreciation allowances are set out in sections 5.3.1 to 5.3.4 of the proposed access arrangement revisions.

817. Western Power proposed retaining the current access arrangement section which specifies depreciation is calculated using:

- the straight line depreciation method;
- the existing weighted average lives for assets that are included in the capital base at the beginning of the access arrangement period (i.e. beginning of AA4); and
- asset lives specified in the access arrangement for capital expenditure during the access arrangement period (i.e. AA4).

818. The ERA was satisfied that this approach was consistent with applying the roll-forward calculation in a manner consistent with the Code objective.

819. Western Power proposed to retain the current access arrangement section specifying the depreciation of the opening capital base for AA5 will be the forecast depreciation included in the AA4 target revenue.

820. Synergy considered the use of forecast depreciation for the purposes of rolling-forward the RAB was not consistent with other elements of WP's proposal. Synergy submitted:

> … the Authority should consider whether the operation of the IAM, as it is proposed by WP, provides sufficient incentive for efficient capex to justify rolling the RAB forward using forecast depreciation.

821. As Synergy indicated, the Investment Adjustment Mechanism only adjusts the return on any under or over expenditure. The forecast depreciation included in target revenue is not adjusted in the following access arrangement period for any under or over expenditure. However, as the forecast depreciation is deducted from the opening capital base, the return and depreciation in future periods is reduced. The ERA considered the current approach of using forecast depreciation provides sufficient incentives for efficient investment and ensures the recovery of return on and return of investment is NPV neutral.

822. Western Power proposed to maintain the economic lives that were applied in AA3 for all assets except distribution meters. It proposed to change the asset life for meters from 25 years to 15 years. Existing metering assets were to continue to be depreciated over 25 years. The 15 year life would apply only to metering expenditure during AA4.

823. The revised asset life for metering assets was consistent with the shorter technical life of the new advanced meters. Western Power already had electronic meters in its asset base. It is likely these had a similar life to the new advanced meters. Consequently, the ERA required Western Power to review its existing metering assets to identify whether the current asset life is consistent with the economic life of those assets.

824. Western Power had not proposed any assets should be subject to accelerated depreciation and removed the current access arrangement section stating that

Western Power will apply accelerated depreciation to any network assets decommissioned as a result of the State Underground Power Project (**SUPP**).

825. The ERA considered this was not consistent with the requirements of the Access Code regarding redundant assets and required Western Power to re-instate the section and include details of redundant assets resulting from the SUPP or any other programs that lead to in-service assets being removed.

826. As required by the ERA, Western Power has reviewed all its metering assets to assess whether the current asset life of the meters is consistent with the economic life of these assets.

827. Western Power has confirmed that all meters installed during AA3 were electronic meters with a 15-year asset life and has adjusted the economic lives of these assets accordingly.

828. Western Power has accepted the ERA's requirement to reinstate the current access arrangement section stating that Western Power will apply accelerated depreciation to any network assets decommissioned as a result of the SUPP. Western Power has also provided details of redundant assets resulting from SUPP or any other programs that lead to in-service assets being removed.

829. Taking into account the above, Western Power's AA4 revised forecast depreciation is set out in Table 120 below.

Table 120 Western Power AA4 revised forecast depreciation ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Transmission	112.2	122.4	134.8	148.8	157.6	675.8
Distribution	258.3	281.6	292.7	293.4	289.4	1,415.4
Distribution accelerated	4.4	6.9	4.4	-	-	15.7

830. In its submission on the draft decision, WAMEU submits Western Power has a depreciation schedule which implies shorter asset lives than generally seen in the NEM. WAMEU submits that if assets are being retired based on their expected lives for each asset type rather than their useful lives, then this would account for a higher replacement expenditure than would be expected.[92]

831. WAMEU also submits that there are ramifications for depreciation as a result of peak demand levels:[93]

> As the network has already been built to match much higher peak demand levels expected in the past this implies there is considerable spare capacity (see section 3) in the network…It also implies that the assets are more lightly loaded and therefore expected to have a longer life than allowed in the depreciation schedule.

832. The ERA has compared Western Power's asset lives with other network service providers. The ERA's review indicates Western Power's asset lives are broadly in

92 WAMEU, *Response to the ERA Draft Decision*, May 2018, p. 47.

93 Ibid, p. 47.

line with other network service providers. The ERA has also not found any evidence that Western Power is retiring assets earlier than other network service providers.

833. The exception to this is “other non-network assets”. Western Power uses an asset life of 16.9 years for transmission and 10.2 years for distribution “other non-network assets”. The mean life used by other network service providers is 27 for assets with long lives and 6 years for assets with short lives.

834. The ERA has reviewed the composition of the expenditure included as “other non-network assets” for AA4. Currently all business support expenditure is allocated to “other non-network assets”. Most of this expenditure is for the depot modernisation program. Some of this expenditure includes land and the remainder is buildings and a mixture of shorter life assets.

835. The ERA has amended the asset classification in the revenue model so that a proportion is allocated to land and amended the asset life to 27 years, based on the average asset life of other network service providers.

836. The ERA’s final decision revised forecast depreciation is set out in Table 121 below.

Table 121 ERA final decision forecast depreciation ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 Total
Transmission	109.7	115.2	122.0	128.8	132.2	607.8
Distribution	258.3	274.9	278.6	269.4	262.5	1,343.6
Distribution accelerated	4.4	6.9	4.4	-	-	15.6

Required Amendment 5

Western Power must amend forecast deprecation for AA4 to the values shown in Table 121 above.

The asset life for “other non-network assets” must be amended to 27 years.

The classification of business support expenditure must be amended to allocate expenditure for land to the correct asset category.

Notional capital base values for AA4

837. The ERA’s draft decision on the notional capital base is set out in Table 122 and Table 123 below.

Table 122 ERA draft decision forecast transmission capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	3,126.0	3,132.3	3175.9	3225.9	3232.3	3,126.0
New facilities investment	117.7	159.9	174.0	139.3	128.6	719.5
Depreciation	(111.4)	(116.3)	(123.9)	(133.0)	(137.4)	(622.0)
Closing asset base	3,132.3	3,175.9	3,225.9	3,232.3	3,223.4	3,223.4

Table 123 ERA draft decision forecast distribution capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	5,791.3	6,009.2	6,223.6	6,465.6	6,595.7	5,791.3
New facilities investment	473.9	489.8	528.9	417.1	419.0	2,328.7
Depreciation	(256.0)	(275.5)	(286.9)	(287.0)	(276.0)	(1,381.4)
Closing asset base	6,009.2	6,223.6	6,465.6	6,595.7	6,738.7	6,738.7

838. The ERA required the following amendment to Western Power's proposal.

Draft Decision 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.

839. As set out above, Western Power did not accept draft decision required amendment 6. Table 124 and Table 125 below set out Western Power's proposed revised forecast capital base for AA4.

Table 124 Western Power's revised forecast transmission capital base ($ million real June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	3,113.8	3,156.9	3,264.7	3,381.9	3,424.7	3,113.8
New facilities investment	153.3	225.9	244.8	181.1	172.6	977.7
Depreciation	(110.1)	(118.0)	(127.7)	(138.3)	(143.9)	(638.0)
Closing asset base	3,156.9	3,264.7	3,381.9	3,424.7	3,453.4	3,453.4

Table 125 Western Power's revised forecast distribution capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	5,827.1	6,061.5	6,292.1	6,539.8	6,671.0	5,827.1
New facilities investment	497.1	519.1	544.8	424.6	425.1	2,410.7
Depreciation	(258.3)	(281.6)	(292.7)	(293.4)	(289.4)	(1,415.4)
Accelerated depreciation	(4.4)	(6.9)	(4.4)			(15.7)
Closing asset base	6,061.5	6,292.1	6,539.8	6,671.0	6,806.6	6,806.6

840. WAMEU's submission on the draft decision raised concerns regarding the RAB:[94]

> The amount of capex allowed in the draft decision will lead to a further increase in the RAB, in both nominal terms and in relative terms (see section 4). As the RAB is already at a level that is imposing hardship on consumers, WAMEU considers that there is a need to reduce the RAB in relative terms and, as a minimum, the RAB should be maintained at a constant level. To achieve this will require the allowed capex not to exceed the depreciation allowance built into the asset base roll forward model.

841. The ERA is required to make its decision on the amount of forecast capital expenditure that can be added to the regulatory asset base based on whether it is satisfied that the proposed expenditure is reasonably likely to meet the new facilities investment test.

842. The ERA has calculated revised values of the notional capital base for AA4 in accordance with the ERA's determinations under this final decision on whether the forecast of new facilities investment may, under section 6.50 of the Access Code, be taken into account in determination of total costs and target revenue.

843. The revised values are set out in Table 126 and Table 127 below.

Table 126 ERA final decision forecast transmission capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	3,108.6	3,122.9	3,185.0	3,237.7	3,231.7	3,108.6
New facilities investment	123.9	177.3	174.7	122.9	123.8	722.6
Depreciation	(-109.7)	(-115.2)	(-122.0)	(-128.8)	(-132.2)	(-608.0)
Closing asset base	3,122.9	3,185.0	3,237.7	3,231.7	3,223.2	3,223.2

94 WAMEU, *Response to the ERA Draft Decision*, May 2018, p. 47.

Table 127 ERA final decision forecast distribution capital base ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Opening asset value	5,798.4	6,008.4	6,208.6	6,442.9	6,582.4	5,798.4
New facilities investment	472.6	482.0	517.3	408.9	411.2	2,292.0
Depreciation	(258.3)	(274.9)	(278.6)	(269.4)	(262.5)	(1,343.6)
Accelerated depreciation	(4.4)	(6.9)	(4.4)			(15.6)
Closing asset base	6,008.4	6,208.6	6,442.9	6,582.4	6,731.1	6,731.1

Required Amendment 6

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

Return on regulated capital base

Access Code requirements

844. Section 6.4 of the Access Code requires that the price control in an access arrangement must (among other things) provide the service provider with an opportunity to earn revenue sufficient to cover its forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

845. The rate of return, based on a weighted average cost of capital (WACC), provides a service provider with a return on the capital it has invested in its business. It is calculated as a return on the regulatory asset base.

846. Section 6.64 of Access Code requires an access arrangement to set out the WACC for a covered network. Under section 6.65, the ERA may from time to time publish a determination of its preferred method for calculating the WACC in access arrangements. If such a determination is in effect at the time of an access arrangement review, the WACC must be determined using that method unless the service provider can demonstrate that an alternative method would better achieve the objectives set out in section 6.4 and the Access Code objective. Otherwise the WACC must be calculated in a manner consistent with section 6.66 of the Access Code.

847. As no determination is in effect, the WACC must be estimated in a manner consistent with section 6.66 of the Access Code. Section 6.66 requires that a WACC calculation:

- must represent an effective means of achieving the Access Code objective and the objectives in section 6.4; and
- must be based on an accepted financial model, such as the Capital Asset Pricing Model.

Western Power's proposal and ERA draft decision

848. In the draft decision, the ERA did not approve Western Power's proposed WACC. Western Power's proposal and the ERA's considerations were detailed in Appendix 5 of the draft decision. In summary, the ERA accepted Western Power's proposed:

- risk free rate (for the cost of equity estimate), updated for current data;
- equity beta, updated for current data;
- risk free rate (for the cost of debt estimate), updated for current data;
- debt risk premium, updated for current data and the use of calendar years;
- the term of debt;
- forecast inflation, updated for current data;
- value of imputation credits (gamma); and
- annual update of the debt risk premium.

849. The ERA made changes to:

- the credit rating;

- the gearing ratio;
- debt raising and hedging costs, correcting for a double counting in the debt raising costs; and
- the market risk premium.

850. The ERA's draft decision is set out in Table 128 below. The detailed reasoning for its decision was set out in Appendix 5 of its draft decision.

Table 128 ERA draft decision on Weighted Average Cost of Capital (WACC) parameters

Parameter	ERA Draft decision	Western Power proposal
Averaging period	29 March 2018	30 June 2017
Cost of equity parameters		
Nominal risk free rate (per cent)	2.37	1.99
Equity beta	0.7	0.7
Market risk premium (per cent)	6.2	7.5
Nominal after tax return on equity (per cent)	**6.71**	**7.24**
Cost of debt parameters		
Five-year interest rate swap (effective yield) (per cent)	2.590	2.290
Debt risk premium (per cent)	2.613	2.790
Benchmark credit rating	BBB+	BBB-/BBB/BBB+
Term of debt for debt risk premium	10 years	10 years
Debt issuing costs (per cent)	0.100	0.125
Debt hedging costs (per cent)	0.114	0.114
Nominal cost of debt (return on debt) (per cent)	**5.42**	**5.32**
Other parameters		
Debt proportion (gearing)	55	60
Forecast inflation rate (per cent)	1.84	1.64
Franking credits (gamma) (per cent)	40	40
Corporate tax rate (per cent)	30	30
Weighted Average Cost of Capital		
Nominal after-tax WACC (per cent)	**6.00**	**6.09**
Real after tax-WACC (per cent)	**4.08**	**4.38**

851. The ERA required the following amendment to Western Power's proposal.

Draft Decision 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 120 of this draft decision and reasoning detailed in Appendix 5 of this draft decision.

852. Western Power did not accept draft decision required amendment 7. Western Power's revised proposal and the ERA's final decision are set out in Table 129 below. The detailed reasons for the ERA's decision are set out in Appendix 5.

Table 129 ERA final decision on Weighted Average Cost of Capital (WACC) parameters

Parameter	ERA final decision	Western Power revised proposal
Averaging period	29 March 2018	29 March 2018
Cost of equity parameters		
Nominal risk free rate (per cent)	2.37	2.37
Equity beta	0.7	0.7
Market risk premium (per cent)	6.0	6.6
Nominal after tax return on equity (per cent)	**6.57**	**6.99**
Cost of debt parameters		
Five-year interest rate swap (effective yield) (per cent)	2.590	2.590
Debt risk premium (per cent)	2.487	2.613
Benchmark credit rating	BBB+	BBB+
Term of debt for debt risk premium	10 years	10 years
Debt issuing costs (per cent)	0.100	0.100
Debt hedging costs (per cent)	0.114	0.114
Nominal cost of debt (return on debt) (per cent)	**5.29**	**5.42**
Other parameters		
Debt proportion (gearing)	55	55
Forecast inflation rate (per cent)	1.84	1.84
Franking credits (gamma) (per cent)	50	40
Corporate tax rate (per cent)	30	30
Weighted Average Cost of Capital		
Nominal after-tax WACC (per cent)	**5.87**	**6.12**
Real after tax-WACC (per cent)	**3.95**	**4.21**

Required Amendment 7

Western Power must amend the (nominal after-tax) weighted average cost of capital to 5.87 per cent, based on the paraeters set out in Table 129 of this final decision and reasoning detailed in Appendix 5 of this final decision.

Return on working capital

Access Code requirements

853. The Access Code does not explicitly contemplate a return on working capital as a cost.

854. The objectives for a price control set out in section 6.4 of the Access Code include giving the service provider an opportunity to earn an amount of target revenue that

meets the forward looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.

Current access arrangement

855. The values of target revenue applying under the price control in the current access arrangement include an allowance for a return on working capital.

856. Working capital refers to a stock of funds that must be maintained by a service provider to pay costs as they fall due. In circumstances where it is the norm for the costs of providing services to be incurred before the revenues from provision of services are received, a stock of working capital may need to be derived from a capital investment in the business. The cost of this stock of working capital (the required return on the capital investment) is a cost to the service provider of operating its business and providing services.

857. For both the transmission and distribution networks, a cost of working capital for each year of the access arrangement was determined as the implicit cost incurred by Western Power by providing credit to users of services and holding inventory offset by the implicit benefit to Western Power of receiving credit from suppliers.

858. The requirement for working capital was calculated using the following assumptions:

- an assumed revenue lag of 45 days, based on meter reading cycles and payment terms of the electricity transfer access contract;
- inventory based on 4 per cent of capital expenditure; and
- an average expense lead of 24.2 days on operating and capital expenditure based on:
  - an expense lead of 10 days on labour costs, comprising 29 per cent of total expense excluding depreciation and borrowing costs;
  - an expense lead of 30 days on direct costs of materials and services, comprising 66 per cent of total expense excluding depreciation and borrowing costs; and
  - an expense lead of 30 days on indirect cost (which includes items such as rates and insurance), comprising 5 per cent of total expense excluding depreciation and borrowing costs.

859. The cost of working capital was calculated as the value of working capital at the beginning of each year of the access arrangement period multiplied by the approved real post-tax WACC.

Western Power's initial proposal

860. Western Power proposed to continue using the same method and assumptions for determining the cost of working capital as approved for AA3. Its initial proposed working capital requirements over AA4 are shown in Table 130 and Table 131 below.

Table 130 Western Power's initial proposed cost of working capital – transmission network ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed target revenue	293.579	343.074	400.911	466.074	539.711
Expenses					
Forecast capital expenditure	168.512	217.653	257.860	230.471	230.712
Forecast operating costs	95.382	86.956	87.312	90.243	91.714
Total expenses	263.893	304.609	345.172	320.714	322.426
Working capital requirement					
Receivables (45 days)	36.195	39.735	43.503	47.642	51.828
Creditors (24.2 days)	(17.496)	(20.196)	(22.823)	(21.264)	(21.377)
Inventory (4% of capital expenditure)	6.740	8.706	10.314	9.219	9.228
Working capital requirement (nominal)	25.439	28.246	30.995	3.597	39.679
Return on working capital at WACC = 6.09%	1.114	1.549	1.720	1.887	2.168

Source: Western Power, AA4 Regulatory Revenue Model, 2 October 2017.

Table 131 Western Power's initial proposed cost of working capital – distribution network ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed target revenue	1221.25	1269.4	1308.1	1340.0	1376.1
Expenses					
Forecast capital expenditure	517.864	537.230	585.230	460.340	483.477
Forecast operating costs	297.310	277.203	279.859	290.957	298.060
Total expenses	815.174	814.406	865.088	751.297	781.537
Working capital requirement					
Receivables (45 days)	150.565	156.496	160.835	165.209	169.654
Creditors (24.2 days)	(54.047)	(53.996)	(57.200)	(49.812)	(51.817)
Inventory (4% of capital expenditure)	20.715	21.488	23.409	18.414	19.339
Working capital requirement (nominal)	25.4	28.2	31.0	35.6	39.7
Return on working capital at WACC = 6.09%	7.238	7.138	7.550	7.736	8.148

Source: Western Power, AA4 Regulatory Revenue model, 2 October 2017.

Submissions on Western Power's initial proposal

861. No submissions were received on working capital.

Draft decision

862. The working capital provided for should only reflect the essential items for the conduct of the service provider's business.

863. Western Power's proposal was consistent with the method approved by the ERA for AA3.

864. The ERA sought further information from Western Power to verify the assumptions used for AA4. Western Power advised it had not identified any information that would indicate the AA3 assumptions should be changed.[95] The ERA did not adjust the assumptions for the purposes of the draft decision but expected Western Power to provide updated information with its response to the draft decision to support its statement that there had been no change in the number of debtor days, creditor days or the proportion of inventory compared with capital expenditure since AA3.

865. The return on working capital was expected to change as a result of amendments elsewhere in the draft decision to the weighted average cost of capital, smoothed target revenue, forecast new facilities investment and forecast non-capital costs.

866. Based on the above reasons, the ERA required the following amendment to Western Power's proposal.

> **Draft Decision 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 revised proposal

867. Western Power's revised proposal states

> 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. (p 127)

868. Western Power submitted the following information to support its working capital parameters.[96]

> **Inventory**
>
> 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).
>
> 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**
>
> 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.

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[95] Email from Western Power 16 February 2018.

[96] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p.126-127.

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

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 majority of meters (type 6260) to be read on a bimonthly basis using best fit schedule route optimisation. Other types of meters (type 1 to 5261) are read on a monthly basis.

Submissions on draft decision

869. No submissions were received on the draft decision.

Considerations of the ERA

870. The ERA has reviewed the information provided by Western Power to support the working capital parameter assumptions and considers they provide a reasonable estimate of the level of inventory, creditors and receivables.

871. Based on the creditor day information provided by Western Power, the AA4 weighted average is 26.09 days compared with 24.2 days for AA3. The ERA has updated the working capital calculation to use the updated creditor day information.

872. The return on working capital will change as a result of amendments elsewhere in this final decision to the weighted average cost of capital, smoothed target revenue, forecast new facilities investment and forecast non-capital costs.

Required Amendment 8

The values of smoothed target revenue, forecast new facilities investment, foreast non-capital costs and weighted average cost of capital used to calculate working capital must be adjusted to be consistent with this final decision.

Taxation

Current access arrangement

873. Prior to AA3, an allowance for taxation costs was included through the use of a "pre-tax" weighted average cost of capital. For AA3 a "post-tax" weighted average cost of capital was used and the revenue model incorporated a tax module to estimate tax liabilities. A tax building block was included in the annual revenue requirement estimate for each year.

874. To implement the post-tax methodology it was necessary to establish the value of the tax asset base as at 30 June 2012 (the initial tax asset base) and the corresponding tax depreciation schedule. Capital contributions were excluded from the initial tax asset base to be consistent with the regulatory accounting treatment. The initial tax asset base was depreciated on a straight-line basis.

875. The initial tax asset base and corresponding tax depreciation approved for AA3 is set out in Table 132 and

876. Table 133 below.

Table 132 Western Power's initial tax asset base for AA3, transmission ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	2,043.3	1,78.4	1,912.0	1,848.5	1,785.6
Tax depreciation	(64.8)	(66.4)	(63.6)	(62.9)	(60.9)
Closing initial tax asset base	1,978.4	1,912.0	1,848.5	1,785.6	1,724.7

Table 133 Western Power's initial tax asset base for AA3, distribution ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	3,127.7	3,40.4	2,955.0	2,874.1	2,794.1
Tax depreciation	(87.3)	(85.4)	(80.9)	(80.0)	(77.3)
Closing initial tax asset base	3,040.4	2,955.0	2,874.1	2,794.1	2,716.8

877. Forecast capital expenditure for the AA3 period was added to the tax asset base in the year it was forecast to be incurred. Tax depreciation can be claimed from the year the asset is commissioned. An assumption was made that typically assets are commissioned the year after the expenditure is incurred. The exception to this was equity raising costs for which depreciation can be claimed from the year the expenditure is incurred.

878. As proposed by Western Power, tax depreciation for capital expenditure during AA3 was calculated on a diminishing value basis.

879. The tax asset lives approved for AA3 are set out in Table 134 below.

Table 134 Tax asset lives approved for AA3 (Years)

	Western Power proposal
Transmission assets	
Cables	47.5
Steel towers	47.5
Wood poles	47.5
Metering	25
Transformers	40
Reactors	40
Capacitors	40
Circuit breakers	40
SCADA and communications	12.5
IT	4

	Western Power proposal
Other non-network assets	12.5
Equity raising costs	5
Distribution assets	
Wooden pole lines	45
Underground cables	50
Transformers	4
Switchgear	30
Street lighting	15
Meters and services	25
IT	4
SCADA and communications	10
Other distribution non-network	10
Equity raising costs	5

880. The forecast tax asset base and tax depreciation for the approved AA3 capital expenditure is set out in Table 135 and Table 136 below.

Table 135 Western Power's forecast tax asset base for approved AA3 capital expenditure, transmission ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	0.0	300.9	679.2	891.0	1,124.1
Tax depreciation	(0.3)	(22.9)	(42.5)	(51.4)	(63.2)
Capital expenditure	301.2	401.2	254.3	284.4	384.5
Closing tax asset base	300.9	679.2	891.0	1,124.1	1,445.4

Table 136 Western Power's forecast tax asset base for approved AA3 capital expenditure, distribution ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	0.0	598.1	1,236.1	1,843.1	2,399.0
Tax deprecation	(2.0)	(49.0)	(92.4)	(123.9)	(152.0)
Capital expenditure	600.1	687.0	699.3	679.7	694.4
Closing tax asset base	598.1	1,236.1	1,843.1	2,399.0	2,941.4

881. Taxable income was calculated as follows:

- approved revenue
- **minus** forecast operating expenditure and TEC[97]

[97] Tariff Equalisation Contribution.

- **minus** tax depreciation
- **minus** interest costs (calculated by multiplying the debt portion of the opening capital base by the gearing ratio used for determining the weighted average cost of capital and the cost of debt)
- **equals** estimated taxable income.

882. The taxation cost was calculated by multiplying the estimated taxable income by the statutory income tax rate of 30 per cent. The estimated taxation payable was calculated by deducting the value of imputation credits.

883. A notional whole of business tax expense and a stand-alone transmission and distribution business tax expense was calculated. The whole of business tax expense was then allocated on the basis of the proportion of the notional tax expense for each business segment.[98]

Western Power's initial proposal

884. For AA4, Western Power proposed a similar method to AA3 to estimate tax liabilities.

885. An update of the initial tax asset base is shown in Table 137 and Table 138 below.

Table 137 Western Power's initial tax asset base, transmission ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	1,724.7	1,666.9	1,609.1	1,551.3	1,493.5
Tax depreciation	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)
Closing initial tax asset base	1,666.9	1,609.1	1,551.3	1,493.5	1,435.7

Table 138 Western Power's initial tax asset base, distribution ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	2,716.8	2,644.3	2,572.8	2,501.3	2,429.8
Tax depreciation	(72.5)	(71.5)	(71.5)	(71.5)	(71.5)
Closing initial tax asset base	2,644.3	2,572.8	2,501.3	2,429.8	2,358.3

886. Western Power also updated the tax asset base to reflect actual capital expenditure during AA3. The revised tax asset base for capital expenditure during AA3 is shown in Table 139 and Table 140 below.

98 Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 237.

Table 139 Western Power's proposed revised tax asset base for actual AA3 capital expenditure, transmission ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	0.0	204.0	512.2	631.2	654.8
Tax depreciation	(0.3)	(15.4)	(28.5)	(37.0)	(43.1)
Capital expenditure	208.5	327.6	156.5	120.1	106.7
Asset disposal	(4.1)	(4.1)	(9.0)	(59.5)	(1.4)
Closing tax asset base	204.0	512.2	631.2	654.8	716.9

Table 140 Western Power's proposed revised tax asset base for actual AA3 capital expenditure, distribution ($ million nominal)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening tax asset base	0.0	628.5	1,224.8	1,754.2	2,149.5
Tax depreciation	(2.1)	(45.8)	(76.6)	(107.6)	(128.2)
Capital expenditure	631.4	642.4	610.7	505.7	364.4
Asset disposal	(0.9)	(0.3)	(4.8)	(2.8)	(0.6)
Closing tax asset base	628.5	1,224.8	1,754.2	2,149.5	2,385.1

887. Western Power rolled forward the tax asset base for the AA4 period by adding capital expenditure (excluding capital contributions and gifted assets), deducting tax depreciation, and deducting asset disposals (at written down tax value). Tax depreciation was calculated using the same asset lives and method approved for AA3. Western Power's forecast tax asset base and depreciation for the AA4 period is set out in Table 141 and Table 142 below.

Table 141 Western Power's initial forecast tax asset base AA4 period, transmission ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening tax asset base	2,441.6	2,504.5	2,606.4	2,736.6	2,823.3
Forecast capital expenditure	168.5	217.7	257.9	230.5	230.7
Forecast tax depreciation (initial tax asset base)	(57.8)	(57.8)	(57.8)	(57.8)	(57.8)
Forecast tax depreciation on capital expenditure since 30 June 2012	(47.8)	(57.9)	(69.8)	(85.9)	(90.7)
Total tax depreciation	(105.6)	(115.8)	(127.7)	(143.7)	(148.5)
Closing tax asset base	2,504.5	2,606.4	2,736.6	2,823.3	2,905.5

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 219.*

Table 142 Western Power's initial forecast tax asset base AA4 period, distribution ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening tax asset base	5,101.9	5,400.3	5,685.5	5,988.7	6,129.2
Forecast capital expenditure	517.9	537.2	585.2	460.3	483.5
Forecast tax depreciation (initial tax asset base)	(72.5)	(71.5)	(71.5)	(71.5)	(71.5)
Forecast tax depreciation on capital expenditure since 30 June 2012	(147.0)	(180.5)	(210.6)	(248.3)	(252.5)
Total tax depreciation	(219.5)	(252.0)	(282.1)	(319.8)	(324.0)
Closing tax asset base	5,400.3	5,685.5	5,988.7	6,129.2	6,288.6

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 219.*

888. A summary of Western Power's initial forecast tax calculations is set out in Table 143, Table 144 and Table 145 below.

Table 143 Western Power's initial estimated cost of taxation for the AA4 period, total business ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Target revenue	1,447.3	1,535.5	1,615.3	1,685.5	1,763.4
Operating expenditure	(392.7)	(364.2)	(367.2)	(381.2)	(389.8)
TEC	(167.0)	(175.0)	(162.0)	(157.0)	(161.0)
Tax depreciation	(325.1)	(367.8)	(409.7)	(463.6)	(472.5)
Interest	(290.7)	(305.3)	(321.5)	(339.6)	(352.6)
Taxable income/(loss)	271.8	323.3	354.9	344.1	387.5
Tax loss brought forward	-	-	-	-	-
Tax loss carried forward	-	-	-	-	-
Taxable profit	271.8	323.3	354.9	344.1	387.5
Taxation (30 per cent of taxable income)	(81.6)	(97.0)	(106.5)	(103.2)	(116.3)

Source: Western Power, AA4 Regulatory Revenue Model, 2 October 2017.

Table 144 Western Power's initial estimated cost of taxation for the AA4 period, transmission ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Target revenue	293.6	322.3	353.8	386.4	420.4
Operating expenditure	(95.4)	(87.0)	(87.3)	(90.2)	(91.7)
TEC					
Tax depreciation	(105.6)	(115.8)	(127.7)	(143.7)	(148.5)
Interest	(100.6)	(104.1)	(109.0)	(114.9)	(119.5)
Taxable income/(loss)	(8.0)	15.4	29.8	37.6	60.6
Tax loss brought forward	(87.2)	(95,2)	(79,7)	(49,9)	(12,3)
Tax loss carried forward	(95.2)	(79.7)	(49,9)	(12,3)	-
Taxable profit	-	-	-	-	48.3
Taxation (30 per cent of taxable income)	-	-			14.5
Allocated tax cost	-	-	-	-	15.0

Source: Western Power, AA4 Regulatory Revenue Model, 2 October 2017.

Table 145 Western Power's initial estimated cost of taxation for the AA4 period, distribution ($ million nominal)

	2017/18	2018/19	2019/20	2020/21	2021/22
Smoothed target revenue	1,153.7	1,213.2	1,261.4	1,299.0	1,343.1
Operating expenditure	(297.3)	(277.2)	(279.9)	(291.0)	(298.1)
TEC	(167.0)	(175.0)	(162.0)	(157.0)	(161.0)
Tax depreciation	(219.5)	(252.0)	(282.1)	(319.8)	(324.0)
Interest	(190.1)	(201.1)	(212.4)	(224.7)	(233.1)
Taxable income/(loss)	279.8	307.9	325.0	306.5	326.9
Tax loss brought forward	-	-	-	-	-
Tax loss carried forward	-	-	-	-	-
Taxable profit	279.8	307.9	325.0	306.5	326.9
Taxation (30 per cent of taxable income)	84.0	92.3	97.5	92.0	98.1
Allocated tax cost	81.6	97.0	106.5	103.2	101.3

Source: Western Power, AA4 Regulatory Revenue Model, 2 October 2017.

Submissions on Western Power's initial proposal

889. Synergy provided the only submission on this matter, and recommended the ERA review Western Power's calculations and assumptions.

Considerations of the ERA

890. In the draft decision, the ERA found two errors in Western Power's determination of the costs of taxation.

- There was an error in Western Power's submitted revenue model. The transmission deferred revenue (caused by re-smoothing) was deducted from both the distribution and transmission revenue for the tax calculation resulting in total revenue used in the calculation of tax being incorrect.
- The revenue under-recovery from AA3 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 taxation allowance.

891. The ERA also considered the method used to allocate between transmission and distribution. It found the current method, which calculates taxation for the total business and then allocates it based on stand-alone tax calculations for each service results in an incorrect allocation between the services when notional tax losses arise in one service. To remove this, the ERA required the allocation to be based on the proportion of revenue for each service.

892. As the ERA determined different values for the parameters used to calculate taxation (including revenue, operating costs and capital expenditure) the forecast taxation cost was be updated to be consistent with these values.

893. Based on the above, the ERA required the following amendment to Western Power's proposal.

> **Draft Decision 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.

894. In its revised proposal, Western Power states it has accepted the required amendment in principle with modification.[99]

> 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).

895. As the ERA has determined different values for the parameters used to calculate taxation (including revenue, operating costs and capital expenditure) in the final decision, Western Power's forecast taxation cost must be updated to be consistent with these values.

896. In its revised proposal Western Power proposes variations to the forecasting tax method.[100]

> 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.
>
> 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:

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99 Western Power p. 129.

100 Western Power p. 129.

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.

The k-factor exclusion results in a downward tax cost adjustment and the IAM exclusion results in an upward tax cost adjustment.

897. The ERA agrees, for the reasons set out in the AA3 decision referred to by Western Power, the revenue adjustment resulting from the investment adjustment mechanism should not be included in the AA4 tax liability. The ERA has amended its revenue model accordingly.

898. Western Power's revised proposal also raises concerns about the tax depreciation of equity raising costs:[101]

> 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 therefore applied the same depreciation calculation to equity raising costs as all other assets for tax depreciation purposes.

899. The ERA has reviewed Western Power's updated calculation and is satisfied it estimates tax depreciation for equity raising costs correctly. The ERA has amended it revenue model accordingly.

900. Western Power's revised proposal raises concerns about the method the ERA has used to allocate taxation between transmission and distribution.[102]

> 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.
>
> 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.
>
> 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.

901. In light of Western Power's submission, the ERA has reconsidered the method it adopted for allocating taxation in the draft decision. The ERA accepts the point made by Western Power that the transmission and distribution networks have different levels of capital and operating expenditure that may affect the taxation position for each network differently.

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101 Western Power p. 129.

102 Western Power p. 130.

902. However, the method Western Power proposes still results in an incorrect allocation between the transmission and distribution networks. The underlying cause is that the current taxation calculation is based on the smoothed revenue profile.

903. If Western Power's target revenue was for a single network (rather than transmission and distribution separately) it would make no difference in net present value terms whether the taxation calculation was based on smoothed or unsmoothed revenue. However, the smoothed revenue profile can result in a notional tax loss in one service, even though there is no tax loss for the total business. Consequently there can be a difference in net present value at the individual service level depending on whether the smoothed or unsmoothed revenue is used, although the value at total business level will be equal.

904. The ERA considers this can be best resolved by using unsmoothed revenue in the tax calculation. This is also consistent with the approach used by the AER. If this approach is used, the tax calculated for each service can be used and there are no notional tax losses in either service.

Required Amendment 9

Forecast taxation costs must be updated to be consistent with the final decision and the calculation must be amended to use unsmoothed revenue for each service.

Adjustments to target revenue

Access Code requirements

905. Section 6.4 of the Access Code provides for the target revenue for an access arrangement period to include certain amounts "carried over" from the previous access arrangement period, including:

- an amount for costs incurred as a result of a force majeure event under sections 6.6 to 6.8 of the Access Code;
- an amount for costs incurred as a result of changes to the Technical Rules, for which no allowance was made in the access arrangement, under sections 6.9 to 6.12 of the Access Code;
- an amount under an investment adjustment mechanism under sections 6.13 to 6.18 of the Access Code;
- an amount under a gain sharing mechanism under sections 6.19 to 6.28 of the Access Code; and
- an amount under a service standards adjustment mechanism under sections 6.29 to 6.37 of the Access Code.

Current access arrangement

906. The current access arrangement provides for several revenue adjustment mechanisms to adjust target revenue in AA3 to account for unforeseen events or other cost pass-throughs, over or under-recovery of revenue in preceding years or

provide financial incentives to Western Power to be more efficient or perform better. These adjustments occur under the following mechanisms:

- Investment adjustment mechanism – an adjustment to account for differences between forecast and actual costs of certain classes of new facilities investment
- Unforeseen events adjustment – an adjustment to account for costs incurred in the current access arrangement period as a result of force majeure events
- Technical rule change revenue adjustment – an adjustment to account for costs incurred as a result of changes to the Technical Rules that could not have reasonably been foreseen at the commencement of the current access arrangement period
- Gain sharing mechanism – an adjustment to account for the out-performance of the forecast operating expenditure in the current access arrangement
- Service standards adjustment mechanism – an adjustment to account for any difference between service standard performance and service standard benchmarks in the current access arrangement
- D-factor – an adjustment to account for any additional operating expenditure incurred as a result of deferring a capital expenditure project, and any additional operating or capital expenditure incurred in relation to demand management initiatives
- Deferred revenue from the current access arrangement – an adjustment to account for the amount of revenue deferred in the current access arrangement (as a result of an alternative treatment of capital contributions) which was to be recovered in subsequent access arrangement periods

Western Power's initial proposal

907. Table 146 summarises Western Power's calculation of the financial implications of the adjustment mechanisms on the AA4 target revenue.

Table 146 Western Power's initial proposed revenue adjustments under AA3 adjustment mechanisms

Adjustment mechanism	Adjustment to AA4 transmission revenue	Adjustment to AA4 distribution revenue
Investment adjustment mechanism	-33.58	-5.89
Gain sharing mechanism	103.69	168.93
Service standard adjustment mechanism	13.4	241.70
D-factor	0.0	8.78
Unforeseen events	5.52	14.19
Technical Rules changes	0.0	0.0
Total	89.03	427.71

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 224.

908. The following sections describe the revenue adjustments under each AA4 mechanism.

Submissions on Western Power's initial proposal

909. Submissions received by the ERA on Western Power's proposed adjustments to target revenue are addressed below under "Considerations of the ERA".

Considerations of the ERA

Investment adjustment mechanism

910. The investment adjustment mechanism is set out in sections 7.3.1 to 7.3.7 of the current access arrangement.

> 7.3.2 An amount will be added to, or deducted from, the target revenue for the next access arrangement period in accordance with the investment adjustment mechanism set out below.
>
> 7.3.3 The investment adjustment mechanism will apply separately to each of:
>
> a) new facilities investment for the transmission system; and
>
> b) new facilities investment for the distribution system.
>
> 7.3.4 The purpose of the investment adjustment mechanism is to adjust Western Power's target revenue in the next access arrangement period in a manner that exactly corrects for the economic loss or gain to Western Power as a result of any investment difference in this access arrangement period in relation to the categories of new facilities investment specified in section 7.3.7 of this access arrangement. In order to give effect to this purpose, the investment adjustment mechanism must take account of:
>
> (a) The effects of inflation;
>
> (b) The time value of money as reflected by Western Power's weighted average cost of capital for the Western Power Network; and
>
> (c) The capital-related costs due to any investment difference in this access arrangement period.
>
> 7.3.5 Given the requirements of the investment adjustment mechanism as described in section 7.3.4 of this access arrangement, Western Power's approach to calculating the capital-related costs due to any investment difference is to calculate the difference in present value terms between:
>
> (a) The target revenue that would have been calculated for this access arrangement period if the investment difference had been zero (i.e. there was no forecasting error in relation to the capital expenditure categories that are subject to the investment adjustment mechanism); and
>
> (b) The target revenue that actually applied in this access arrangement period.
>
> The amount under section 7.3.2 of this access arrangement is equal to the present value of the difference calculated under section 7.3.5 of this access arrangement.
>
> 7.3.7 The categories that are used in calculating the investment difference are new facilities investment:
>
> (a) arising from the connection of new generation capacity to the transmission system or distribution system from 1 July 2012;
>
> (b) arising from the connection of new load to the transmission system or distribution system from 1 July 2012;

(c) in relation to all augmentations to provide additional capacity to the transmission system or distribution system for the provision of covered services from 1 July 2012;

(d) Undertaken for augmentation of the distribution system under the rural power improvement program;

(e) undertaken for augmentation of the distribution system under the state underground power program; and

(f) in relation to distribution system wood pole management for the provision of covered services from 1 July 2012.

911. Prior to AA3, the investment categories subject to the investment adjustment only included capacity expansion and customer driven categories, on the basis that the drivers for this expenditure are outside Western Power's control.

912. Distribution wood pole management expenditure was added to the mechanism for AA3. Western Power's performance and strategy for managing wood poles was a major issue for AA3. Western Power had been issued with an Order by EnergySafety and was also subject to an inquiry by the Legislative Council's Standing Committee on Public Administration.

913. In its final decision for AA3, the ERA recognised that the investment needs for wood pole management may change as Western Power further developed its understanding of what is required. The ERA noted:

> To ensure that Western Power is incentivised to do this in an efficient manner, the Authority decided that, for the third access arrangement period, expenditure relating to wood pole management should be subject to the investment adjustment mechanism. This will then enable expenditure higher than forecast to be recovered, to the extent that it is demonstrated to be efficient expenditure, and will provide Western Power with a return on that investment from the date it is incurred. Alternatively, the provisions of the Access Code enable Western Power to apply to the Authority at any time for pre-approval of capital expenditure forecasts. All of these provisions ensure Western Power is not constrained to only spend what is allowed in the current forecast.

914. Western Power calculated adjustments of $33.6 million for transmission and $5.9 million for distribution that will be returned to customers due to actual expenditure being lower than approved. These calculations are summarised in Table 147 and Table 148 below.

Table 147 Western Power's proposed adjustments to target revenue under the investment adjustment mechanism – transmission network ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Approved capital expenditure					
Capacity expansion	212.5	299.0	143.7	154.4	244.1
Customer-driven	12.5	21.8	21.8	22.0	22.4
Total	225.0	320.8	165.5	176.4	266.5
Actual capital expenditure					
Capacity expansion	122.5	215.6	90.4	27.8	31.3
Customer-driven	21.2	40.5	(22.9)	(0.3)	(8.9)
Total	143.7	256.1	67.6	27.5	22.4
Above or (below) approved expenditure					
Capacity expansion	(89.9)	(83.4)	(53.3)	(126.6)	(212.8)
Customer-driven	8.7	18.7	(44.7)	(22.3)	(31.4)
Total	(81.3)	(64.7)	(98.0)	(148.9)	(244.1)
Adjustment to target revenue Compound return based on the AA3 WACC of 3.6 per cent.	-	(2.9)	(5.3)	(8.8)	(14.16)
Amount (deducted)/added from/to target revenue in 2017/18	(33.6)				

Source: Western Power, AA4 Regulatory Revenue Model, 2 October 2017.

Table 148 Western Power's proposed adjustments to target revenue under the investment adjustment mechanism – distribution network ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Approved capital expenditure					
Capacity expansion	62.7	67.6	75.1	75.5	84.2
Customer-driven	142.7	142.2	144.1	143.4	146.4
State Underground Power Program	10.0	4.8	-	-	-
Wood pole management	181.4	207.7	219.5	231.3	245.1
Total	396.8	422.3	438.7	450.2	475.7
Actual capital expenditure					
Capacity expansion	52.2	41.1	26.9	25.9	35.5
Customer-driven	121.9	93.5	88.6	60.3	46.2
State Underground Power Program	16.5	9.3	6.0	4.8	5.0
Wood pole management	233.5	295.3	241.2	190.1	81.7
Total	424.1	439.2	362.7	281.0	168.5
Above or (below) approved investment					
Capacity expansion	(10.5)	(26.5)	(48.1)	(49.6)	(48.7)
Customer-driven	(20.8)	(48.7)	(55.5)	(83.1)	(100.2)
State Underground Power Program	6.5	4.5	6.0	4.8	5.0
Wood pole management	52.1	87.6	21.7	(41.3)	(163.4)
Total	27.3	16.8	(76.0)	(169.2)	(307.2)
Adjustment to target revenue Compound return based on the AA3 WACC of 3.6 per cent.	-	0.98	1.59	(1.15)	(7.25)
Amount (deducted)/added from/to target revenue in 2017/18	(5.89)				

Source: Western Power, AA4 Regulatory Revenue Model, 2 October 2017.

915. In its assessment of the amounts proposed by Western Power under the investment adjustment mechanism, the ERA addressed:

- whether the amounts to be added to the target revenue were calculated correctly and consistently with the methods of financial modelling applied for the determination of target revenue; and
- whether the above-forecast new facilities investment was able to be added to the capital base for the network under section 6.51A of the Access Code, allowing Western Power to earn a return on the investment.

916. Consistency of the calculation of amounts to be added to target revenue with the methods of financial modelling applied for the determination of target revenue requires consistency with the implicit timing assumptions for costs and revenues and with the methods applied in calculating the capital base. The ERA verified Western Power's calculations and was satisfied that the calculation method had been undertaken appropriately.

917. In its review of the opening capital base, the ERA identified expenditure that did not meet the new facility test investment requirements and therefore was to be removed from the opening capital base. The adjustment under the Investment Adjustment Mechanism also changed as a result. Western Power was to update the Investment Adjustment Mechanism calculation to be consistent with the draft decision on the opening capital base.

918. The ERA's draft decision included the following required amendment.

> **Draft Decision Required Amendment 10**
>
> Western Power must update the Investment Adjustment Mechanism value to reflect the ERA's draft decision on AA3 capital expenditure.

919. In its revised proposal, Western Power states it has accepted draft decision required amendment 10 in principle with modifications.[103]

> 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.

920. As set out in this final decision (paragraph 517 further following), the ERA has decided to amend Western Power's wood pole capital expenditure to remove $28.9 million that should have been treated as operating expenditure to be consistent with the accounting policies in place when the AA3 decision on capital and operating expenditure was made. Consequently, Western Power must amend its revenue adjustment for the investment adjustment mechanism to reflect the ERA's final decision on AA3 capital expenditure.

Required Amendment 10

Western Power must update the Investment Adjustment Mechanism value to reflect the ERA's final decision on AA3 capital expenditure.

Gain sharing mechanism

921. The gain sharing mechanism provides an additional incentive to Western Power to achieve operating cost efficiencies during an access arrangement period as it ensures Western Power retains the efficiency saving for five years from when the efficiency is achieved. For example, without this mechanism, efficiency savings

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made in year one would be retained for five years but savings in year five would only be retained for one year. Consequently, there would be less incentive to make efficiency savings in the latter years of an access arrangement period.

922. The gain sharing mechanism is set out in sections 7.4.1 to 7.4.9 of the current access arrangement. Section 7.4.2 specifies the annual "efficiency and innovation benchmarks" against which Western Power's actual performance will be assessed and the formula for calculating the costs for comparison purposes.

Table 149 AA3 efficiency and innovation benchmarks ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Total forecast operating expenditure	498.8	501.6	497.7	495.0	507.7
Less forecast costs for defined benefit superannuation schemes	3.2	3.3	3.3	3.4	3.4
Less forecast non-revenue cap services cost	0	0	0	0	0
Less forecast licence fees	0.05	0.05	0.05	0.05	0.05
Less forecast energy safety levy	4.52	4.52	4.52	4.52	4.52
Less network control service	0	0	0	0	0
Less amounts payable under the *ERA (Electricity Network Access Funding) Regulations 2012*	0.99	1.54	1.32	1.32	1.32
Efficiency and innovation benchmark forecast	490.0	492.4	488.4	485.8	498.3

923. The forecast scale factors used to derive the efficiency and innovation benchmark for AA3 are replaced with the actual scale factors when calculating the above-benchmark surplus at the end of AA3. This ensures Western Power will not be rewarded or penalised for variations from forecast operating expenditure that are attributable to differences in the scale factors driving expenditure and that, conversely, customers do not pay more under the gain sharing mechanism because of slower growth. The scale factors are:

- customer numbers;
- line length;
- distribution transformers;
- zone substation capacity; and
- network growth factor.

924. The forecast scale escalation assumptions and formula for updating the efficiency and innovation benchmarks are set out in section 7.4.8 of the access arrangement. Section 7.4.9 includes requirements for the actual scale escalation factors to be independently audited.

925. The formulation detailed in section 7.4 is summarised in the following tables. Western Power updated the values for EIB_t[104] and A_t[105] for each year for actual audited scale escalation factors. Western Power engaged Deloitte to perform an audit of the efficiency and innovation scale escalation factors for the AA3 period.[106]

926. Deloitte found:[107]

> In our opinion, based on the procedures performed, in all material respects:
>
> - The data used in the calculation of the scale escalation drivers for the purposes of AA3 section 7.4.8(b)(i) for the 2011/12 to 2016/17 financial years is valid and has been accurately and completely applied
> - The scale escalation drivers are calculated in accordance with the methodology set out in table 34 of AA3.

[104] Efficiency and Innovation Benchmarks at time t.

[105] Actual non-capital costs at time t.

[106] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 226.

[107] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period - Attachment 10.3: Audit of Efficiency and Innovation Benchmark scale escalation drivers for the period 2011/12 to 2016/17*, 2 October 2017, p. 4.

Table 150 Western Power's initial proposed adjusted benchmark for actual scale escalation drivers ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Efficiency and innovation benchmark approved for AA3–based on forecast scale escalation drivers	$490.0	$492.4	$488.4	$485.8	$498.3
Benchmark scaling factors:					
Customer numbers escalation	2.41%	2.41%	2.41%	2.41%	2.41%
Network growth escalation	2.1%	2.1%	2.1%	2.1%	2.1%
Line length	1.31%	1.31%	1.31%	1.31%	1.31%
Number of distribution transformers	1.33%	1.33%	1.33%	1.33%	1.33%
Zone substation capacity	3.65%	3.65%	3.65%	3.65%	3.65%
Actual scaling factors:					
Customer numbers escalation	3.41%	0.68%	2.49%	2.37%	1.54%
Network growth escalation	0.46%	2.33%	0.62%	-0.37%	0.56%
Line length	0.09%	1.35%	1.35%	0.79%	0.53%
Number of distribution transformers	0.47%	1.5%	1.11%	0.85%	0.64%
Zone substation capacity	0.82%	4.15%	-0.61%	-2.76%	0.51%
Reduction in the benchmark due to growth being lower than forecast	($3.1)	($3.2)	($6.7)	($12.8)	($16.9)
Efficiency and innovation benchmark – adjusted for actual scale escalation drivers	$486.9	$489.2	$481.7	$473.0	$481.4

Table 151 Western Power's initial proposed actual expenditure for gain sharing mechanism ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Total operating expenditure	530.9	510.6	482.0	511.8	456.7
Less costs for defined benefit superannuation schemes	(0.1)	(0.5)	-	(0.3)	(0.3)
Less non-revenue cap services cost	(34.0)	(17.5)	(16.6)	(17.7)	(17.2)
Less licence fees	(0.1)	(0.1)	(0.4)	-	-
Less energy safety levy	(4.3)	(4.3)	(4.3)	(4.4)	(4.4)
Less network control service	(2.1)	(1.8)	(1.7)	(1.5)	(0.6)
Less amounts payable under the ERA (Electricity Network Access Funding) Regulations 2012	(0.8)	(0.8)	(0.4)	(0.8)	(0.5)
Unforeseen events			(0.7)	(4.5)	(13.4)
Efficiency and innovation actuals	489.5	485.6	457.9	482.6	420.3

927. The gain sharing mechanism also includes provisions to ensure expenditure savings achieved by, or resulting in, failure to meet service standard benchmarks are not rewarded.

> $272.6 million is included in AA4 target revenue as a result of performance under the GSM during the AA3 period. The GSM provides Western Power an incentive to make operating cost efficiencies by allowing the business to add a share of efficiency gains achieved during one access arrangement period to target revenue for the next access arrangement period. Efficiency improvements must not be made at the expense of service performance, therefore GSM rewards are only applied if Western Power achieves a defined set of minimum service standards. Customers receive the majority of the benefits as a result of the significantly lower operating expenditure in future periods.
>
> … The current GSM requires Western Power to achieve all 17 SSBs in any one year in order to receive efficiency rewards. The business met all 17 SSBs in two of the five years of the AA3 period. [108]

Table 152 Western Power's initial calculation of inputs for gain sharing mechanism calculation ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Efficiency and innovation benchmark – adjusted for actual scale escalation drivers	486.9	489.2	481.7	473.0	481.4
Actual costs	489.5	485.6	457.9	482.6	420.3
Benchmark less actual (current year) (A)	(2.6)	3.6	23.8	(9.6)	61.1
Benchmark less actual (prior year) (B)		2.6	(3.6)	(23.8)	9.6
Above benchmark surplus/(loss) (A)+(B)	(2.6)	6.2	20.2	(33.5)	70.8
Above benchmark surplus adjusted for service standard performance	(2.6)	0.0	20.2	(33.5)	70.8

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 227.

928. In its initial proposal, Western Power calculated the reward payable in each year of AA4 as follows.

Table 153 Western Power's initial proposed gain sharing mechanism ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
2012/13	(2.6)				
2013/14	0.0	0.0			
2014/15	20.2	20.2	20.2		
2015/16	(33.5)	(33.5)	(33.5)	(33.5)	
2016/17	70.8	70.8	70.8	70.8	70.8
Total	**54.9**	**57.5**	**57.5**	**37.3**	**70.8**

[108] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 226.

929. The current access arrangement specifies the gain sharing mechanism reward as a whole of Western Power reward without specifying how this should be allocated between distribution and transmission. In its initial proposal, Western Power calculated a notional gain sharing mechanism reward for distribution and transmission separately, and used these outcomes to allocate the total reward to transmission and distribution.

Table 154 Western Power proposed allocation between transmission and distribution ($ million real June 2017)

	2017/18	2018/19	2014/15	2015/16	2016/17
Total - $GSMA_t$	54.9	57.5	57.5	37.3	70.8
Distribution allocation	36.4	37.5	34.8	13.3	46.9
Transmission allocation	18.5	20.0	22.7	24.0	23.9

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 227.

930. The ERA's draft decision included required amendments that affect the gain share mechanism. As set out in Table 155 below, an adjustment was required for wood pole operating expenditure and the amounts Western Power claimed as unforeseen events were required to be removed.

Table 155 ERA draft decision gain sharing mechanism ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Total reported operating expenditure	530.9	510.6	482.0	511.8	456.7
Adjustment for wood pole operating expenditure			10.5	12.9	5.5
Less costs for defined benefit superannuation schemes	(0.1)	(0.5)	-	(0.3)	(0.3)
Less non-revenue cap services cost	(34.0)	(17.5)	(16.6)	(17.7)	(17.2)
Less licence fees	(0.1)	(0.1)	(0.4)	-	-
Less energy safety levy	(4.3)	(4.3)	(4.3)	(4.4)	(4.4)
Less network control service	(2.1)	(1.8)	(1.7)	(1.5)	(0.6)
Less amounts payable under the ERA (Electricity Network Access Funding) Regulations 2012	(0.8)	(0.8)	(0.4)	(0.8)	(0.5)
Less unforeseen events	-	-	-	-	-
Total actual efficiency and innovation expenditure	489.5	485.6	469.1	500.0	439.2
Efficiency and Innovation Benchmark	486.9	489.2	481.7	473.0	481.4
Benchmark less actual (current year)	(2.6)	3.6	12.6	(27.0)	42.2
Benchmark less actual (prior year)		2.6	(3.6)	(12.6)	27.0
Annual surplus	(2.6)	6.2	9.0	(39.6)	69.2
Adjusted for service standard performance	(2.6)	-	9.0	(39.6)	69.2

Table 156 ERA draft decision gain sharing mechanism ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
2012/13	-2.6				
2013/14	0.0	0.0			
2014/15	9.0	9.0	9.0		
2015/16	(39.6)	(39.6)	(39.6)	(39.6)	
2016/17	69.2	69.2	69.2	69.2	69.2
Total	**36.0**	**38.6**	**38.6**	**29.6**	**69.2**

931. As the gain share mechanism was set on the basis of total business performance, the ERA allocated the total value between services based on revenue proportions as set out in Table 157 below.

Table 157 ERA draft decision allocation of gain share mechanism between transmission and distribution ($ million real June 2017)

	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission	8.6	9.3	9.3	7.1	16.6
Distribution	27.4	29.3	29.3	22.5	52.6
Total	**36.0**	**38.6**	**38.6**	**29.6**	**69.2**

932. Based on the above, the ERA required the following amendment to Western Power's proposal.

> **Draft Decision 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.

933. In its revised proposal, Western Power states it has accepted draft decision required amendment 11 in principle with modifications.[109]

> 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.
>
> 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.
>
> 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.

Considerations of the ERA

934. Western Power has complied with part of required amendment, allocation between services based on revenue split, but must comply with the full amendment that requires all values to be consistent with the ERA's decision.

> **Required Amendment 11**
>
> Western Power must update the Gain Share Mechanism to reflect the ERA's final decision on wood pole expenditure and unforeseen events.

109 Western Power, pp. 131-132.

Service standard adjustment mechanism

935. The service standard adjustment mechanism underwent major revisions at the last access arrangement review. The changes were initiated by Western Power to more closely align the methodology with the comparable NEM incentive mechanism (Service Standard Performance Incentive Scheme).

936. The service standard adjustment mechanism is intended to ensure Western Power has an incentive to maintain service standards and improve service standards only where the improvement is of value to customers.

937. Western Power forecast a cumulative net reward of $13.4 million for transmission and $241.7 million for the distribution service for the AA3 period.

938. Western Power calculated an overall $13.4 million reward under the service standard adjustment mechanism for performance against the transmission network service standard targets during the AA3 period. Table 158 shows performance compared with the service standard target and the financial penalty or reward for each measure.

Table 158 Western Power AA3 transmission service standard adjustment mechanism adjustments ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Circuit availability (% of total time)					
Target	98.1	98.1	98.1	98.1	98.1
Performance	98.4	98.0	98.5	98.7	98.9
Penalty / reward $	**2.7**	**-0.5**	**3.6**	**5.4**	**7.2**
System minute interrupted radial (minutes)					
Target	1.9	1.9	1.9	1.9	1.9
Performance	1.2	3.7	1.6	0.5	0.7
Penalty / reward $	**0.1**	**-0.3**	**0.0**	**0.2**	**0.1**

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, pp. 227-228.

939. Western Power calculated an overall $241.7 million reward under the service standard adjustment mechanism for performance against the distribution network service standard targets during the AA3 period. Table 159 (below) shows performance compared with the service standard target and the financial penalty or reward for each measure.

940. Western Power calculated an overall $9.2 million reward under the service standard adjustment mechanism for performance against the call centre performance service standard targets during the AA3 period. Table 160 (below) shows performance compared with the service standard target and the financial penalty or reward for the measure.

941. Western Power's calculation of the Service Standard Adjustment Mechanism has been calculated in accordance with the access arrangement.

Table 159 Western Power AA3 distribution service standard adjustment mechanism adjustments ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
SAIDI - CBD (minutes)					
Target	20.3	20.3	20.3	20.3	20.3
Performance	7.6	18.3	26.2	22.6	13.8
Penalty / reward $	**0.9**	**0.1**	**-0.4**	**-0.2**	**0.5**
SAIDI - Urban (minutes)					
Target	136.6	136.6	136.6	136.6	136.6
Performance	102.7	107.4	103.0	91.3	104.4
Penalty / reward $	**19.8**	**17.1**	**19.6**	**26.5**	**18.8**
SAIDI – Rural short (minutes)					
Target	207.8	207.8	207.8	207.8	207.8
Performance	181.4	171.2	182.6	168.4	175.6
Penalty / reward $	**6.5**	**9.0**	**6.2**	**9.7**	**7.9**
SAIDI - Rural long (minutes)					
Target	582.2	582.2	582.2	582.2	582.2
Performance	685.4	673.8	677.5	582.6	626.2
Penalty / reward $	**-7.4**	**-6.6**	**-6.9**	**0.0**	**-3.2**
SAIFI – CBD (number of instances)					
Target	0.14	0.14	0.14	0.14	0.14
Performance	0.03	0.20	0.17	0.10	0.11
Penalty / reward $	**1.1**	**-0.6**	**-0.3**	**0.4**	**0.3**
SAIFI – Urban (number of instances)					
Target	1.36	1.36	1.36	1.36	1.36
Performance	1.16	1.13	1.09	0.91	1.00
Penalty / reward $	**12.1**	**13.9**	**16.3**	**27.2**	**20.6**
SAIFI – Rural short (number of instances)					
Target	2.27	2.27	2.27	2.27	2.27
Performance	2.17	1.83	1.98	1.75	1.76
Penalty / reward $	**2.5**	**10.8**	**7.1**	**12.8**	**12.5**
SAIFI – Rural long (number of instances)					
Target	4.06	4.06	4.06	4.06	4.06
Performance	4.91	4.98	4.41	3.99	3.95
Penalty / reward $	**-5.0**	**-5.0**	**-3.9**	**0.8**	**1.2**

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, pp. 228-229.

Table 160 Western Power AA3 call centre performance service standard adjustment mechanism adjustments ($ million real June 2017)

		2012/13	2013/14	2014/15	2015/16	2016/17
Call centre performance (% calls responded to within 30 seconds)						
Target	%	87.6	87.6	87.6	87.6	87.6
Performance	%	90.6	92.8	93.7	91.4	91.8
Penalty / reward	**$m**	**1.4**	**2.4**	**2.8**	**1.7**	**1.9**

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 229.

D-factor

942. The D-factor mechanism provides for the recovery in the next access arrangement period of operating expenditure that is incurred by Western Power as a result of deferring a capital expenditure project or in relation to demand-management initiatives.

943. Many non-network options (including demand management programs) involve substituting non-capital costs for capital investment in a network to resolve network constraints. However, the Access Code does not include a mechanism for the retrospective recovery of non-capital costs. The inability to recover these costs could result in Western Power not choosing the overall least cost option.

944. The D-factor scheme was approved in AA2 to remove the apparent disincentive for Western Power to seek efficiency in capital costs where an increase in non-capital costs was necessary to achieve the efficiency on the basis that, otherwise, such non-capital costs could not be recovered.

945. The types of expenditure and the evidence Western Power must provide to support a claim under the D-factor are set out in sections 7.6.3 to 7.6.5.

7.6.3 In the next access arrangement period, the Authority will add to Western Power's target revenue an amount so that Western Power is financially neutral as a result of:

a) any additional non-capital costs incurred by Western Power as a result of deferring a new facilities investment project during this access arrangement period, net of any amounts previously included in target revenue in relation to the deferred new facilities investment (other than such amounts included in the calculation of the capital-related costs due to any investment difference under clause 7.3.5); and

b) any additional non-capital costs incurred by Western Power in relation to demand management initiatives or network control services.

7.6.4 In relation to 7.6.3a), the new facilities investment project that has been deferred must have been included in the forecast new facilities investment in its revised access arrangement information or supporting documentation, and in the Authority's allowed new facilities investment for this access arrangement period.

7.6.5 In relation to 7.6.3a) and 7.6.3b), an amount will only be added to target revenue for the next access arrangement period if there is an approved business case for the relevant expenditure, and this business case is made available to the Authority. The business case must demonstrate to the Authority's satisfaction that the proposed non-capital costs satisfy the requirements of sections 6.40 and 6.41 of the Code, as relevant.

7.6.6 In relation to 7.6.3a) and 7.6.3b), the adjustment to the target revenue for the next access arrangement period must leave Western Power financially neutral by taking account of:

a) the effects of inflation; and

b) the time value of money as reflected by Western Power's weighted average cost of capital for the Western Power network.

946. In its initial proposal, Western Power sought an adjustment of $8.8 million to recover costs of the Ravensthorpe and Bremer Bay network control services. Section 7.6 of the current access arrangement permits Western Power, in certain circumstances, to recover non-capital costs through the D-factor scheme.

947. Western Power stated that network control services enable it to procure generation and demand management in localised areas of network constraint to defer the need for more costly network augmentation. Western Power advised that the Ravensthorpe Power Station has been providing network control services since 2012/13, while Bremer Bay has been in operation since 2006. In both cases, localised generation can be dispatched in response to network contingencies at peak times and during lengthy outages to ensure covered services can be provided and reliability is not compromised.

948. In accordance with the requirements of the access arrangement, these network control services are for demand management or will enable network augmentation to be deferred. Western Power considered this operating expenditure is compliant with the requirements of Sections 6.40 and 6.41 of the Access Code.

Table 161 Western Power AA4 D-factor revenue adjustment ($ million real June 2017)

	2012/13	2013/14	2014/15	2015/16	2016/17
Ravensthorpe	1.2	0.8	0.6	0.6	0.6
Bremer Bay	0.9	1.0	1.1	0.9	0.1
Total	**2.1**	**1.8**	**1.7**	**1.5**	**0.7**

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 230.

949. No stakeholders commented on these adjustments.

950. Western Power provided business cases and supporting information that demonstrated the expenditure claimed meet the D-factor requirements.

951. Western Power's AA3 proposal forecast expenditure of $73 million for network control services. The ERA's decision for AA3 was to exclude network control service costs from the approved operating costs and expand the D-factor scheme to enable Western Power to recover the actual costs at the next review. As can be seen above, total actual network control costs amounted to $7.8 million.

3Unforeseen events adjustment

952. The unforeseen events adjustment is set out in sections 7.1.1 to 7.1.4 of the current access arrangement as follows:

7.1.1 If a *force majeure event*[110] occurs which results in Western Power incurring *unrecovered costs* during the *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 *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*.

7.1.2 Pursuant to sections 6.6 to 6.8 of the Code, an amount will be added to the *target revenue* for the *covered network* for the next *access arrangement period* in respect of the *unrecovered costs* relating to a *force majeure event* which occurred in the *access arrangement period*.

7.1.3 The addition to target revenue in the next access arrangement period must leave Western Power financially neutral given the timing of when Western Power incurred any unrecovered costs by taking account of:

a) the effects of inflation; and

b) the time value of money as reflected by Western Power's weighted average cost of capital for the Western Power Network.

7.1.4 A *force majeure event* includes but is not limited to any costs arising from the introduction of any scheme or mechanism with respect to any activity including pricing, reduction, cessation, offset and sequestration (including the Carbon Pricing Mechanism announced by the Commonwealth in February 2011), full retail contestability, and the mandated roll-out of Advanced Interval Meters to the extent that such costs were not included in the calculation of target revenue for this access arrangement period or otherwise addressed through the trigger event provisions in section 8 of this access arrangement.

953. In its initial proposal, Western Power submitted that the electricity market review meets the Access Code requirements for a force majeure event:

> … the EMR was a State Government-led initiative that proposed a series of reforms to the Western Australian energy sector. The EMR had two phases, the first of which was largely investigatory and resulted in Western Power incurring some discretionary costs. The second phase laid out specific market reform, which imposed significant mandatory costs on Western Power.
>
> The need to incur EMR costs was outside Western Power's control. The EMR was not foreseen at the beginning of the AA3 period, therefore no forecast costs were included in the AA3 access arrangement decision. These costs are not recoverable under Western Power's insurance policies.

954. Western Power stated it reviewed the costs and identified those incurred in Phase 2 directly related to the introduction of the review. It adopted the following accounting treatment:[111]

- costs that were incurred of a capital nature were capitalised (e.g. IT costs)

[110] The Access Code defines "force majeure" as a fact or circumstance beyond the person's control and which a reasonable and prudent person would not be able to prevent or overcome.

[111] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 231.

- costs that had potential to provide a benefit to Western Power should it transition to the National Electricity Rules in the future were capitalised
- all remaining costs were expensed (i.e. operating expenditure).

955. Table 162 and Table 163 (below) summarise the electricity market review operating expenditure and capital expenditure that Western Power has included as a force majeure event in the AA4 proposal. The tables also show the operating expenditure and capital expenditure amounts of the proposed force majeure event. The revenue adjustment due to operating expenditure is $19.7 million (in present value terms).

956. Western Power proposed the capital expenditure it had identified should be added to the regulated capital asset base. The amounts are shown in the table below for completeness. The ERA considered the proposed capital expenditure amount under the opening regulated capital base for AA4.

Table 162 Western Power summary of electricity market review operating expenditure incurred ($ million real June 2017)

	Total cost incurred	Less excluded costs	Total force majeure
Network regulation – regulatory submission program	8.8	-2.6	6.2
Market competition – contestability	1.4	-	1.4
Market competition – connections and access	2.0	-	2.0
Institutional arrangements – System Management /AEMO	4.6		4.6
Review program management – electricity market review transition	4.3		4.3
Total	**21.3**	**-2.6**	**18.7**

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, *2 October 2017, p. 232.*

Table 163 Western Power summary of electricity market review capital expenditure incurred ($ million real June 2017)

	Total cost incurred	Less excluded costs	Total force majeure
Network regulation – regulatory submission program	5.6	-0.06	5.6
Institutional arrangements – System Management /AEMO	0.5		0.5
Review program management – electricity market review transition	0.3		0.3
Total	**6.4**	**-0.06**	**6.4**

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, *2 October 2017, p. 232.*

957. Submissions on Western Power's initial proposal from Alinta, CdL Advisory, Change Energy, Community Electricity, Emergent Energy, ERM Power and Synergy all

include discussion of the costs of energy market reform. Generally submissions considered this expenditure should not be included as an unforeseen event adjustment.

958. In addition to meeting the requirements of a force majeure event, section 6.6 of the Access Code only permits costs that would be incurred by a service provider efficiently minimising costs. Furthermore, under section 6.4 of the Access Code, the costs must be for the provision of covered services.

959. The ERA considered each element of the costs submitted by Western Power against the Access Code requirements:

Preparation of a possible regulatory submission to the Australian Energy Regulator

960. The ERA noted there was no regulatory obligation for this submission to be prepared. Western Power did not provide any evidence to demonstrate that the costs are no greater than would be incurred by a service provider efficiently minimising costs. The ERA did not consider these costs met the Access Code requirements for an unforeseen event adjustment.

Market competition contestability, connections and access and review program management for electricity market review transition

961. The ERA did 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.

System Management/AEMO

962. As discussed in the opening capital base, system management costs do not form part of Western Power's regulated network services. Prior to AEMO taking on these functions, Western Power recovered its system management costs through wholesale electricity market fees. Since AEMO took on responsibility for System Management, Western Power has been charging AEMO for the services it has provided. Consequently, the ERA did not consider these costs fell within the requirements of the Access Code for the unforeseen events adjustment.

963. Based on the above reasons, the ERA required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 12**
>
> Western Power must adjust target revenue to remove its proposed unforeseen event adjustment.

Western Power revised proposal

964. In its revised proposal, Western Power has not accepted draft decision required amendment 12. Western Power refers to the ERA's view that:[112]

> … 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.

[112] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p.133.

> Western Power submits it 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.
>
> 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.
>
> 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. 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.
>
> 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."
>
> 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.
>
> 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 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.

965. As set out in the draft decision, the recovery of costs through the unforeseen events adjustment only applies to costs for the provision of covered services[113] and only those costs that would be incurred by a service provider efficiently minimising costs.[114]

966. In its initial proposal, Western Power submitted that the second phase of the "State Government-led initiative that proposed a series of reforms to the Western Australian energy sector" imposed "significant mandatory costs on Western Power".

967. In its revised proposal, in response to the ERA's view that there was no regulatory obligation for Western Power to prepare a submission to the AER, Western Power submitted the Access Code does not require a regulatory obligation to be implemented for an event to be considered unforeseen.

968. While the ERA agrees that Western Power could not have foreseen that the State Government would carry out a major review of the electricity market review during AA3, as noted above, the unforeseen events adjustment can only include costs for the provision of covered services and only those costs that would be incurred by a

[113] The provision to include costs for force majeure events (section 6.4(a)(iii) of the Access Code) falls under section 6.4(a) which gives the "*service provider* an opportunity to earn revenue … from the provision of *covered services* …".

[114] Section 6.6 of the Access Code is subject to section 6.8 which states "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*."

service provider efficiently minimising costs. It is not enough for them to be “unforeseen”.

969. The ERA acknowledges that Western Power, as a State Government owned entity, was requested by the State Government to undertake certain actions to assist with the reform program of the Electricity Market Review. These actions included a contribution of funds towards the cost of the Electricity Market Review, contribution of staff to the review team, participation in the Steering Committee, preparatory work for transition to the national regulatory framework and implementation of other reform elements, and the transfer of System Management Functions to the AEMO.

970. Arguably these costs could be considered as mandatory for Western Power as they were required by the State Government to assist in the review. However, they were not required for the provision of covered services. They were also not costs that would be incurred by a service provider efficiently minimising costs as the obligations to undertake these actions would not have been imposed on a private sector entity, at least not in the same manner and before the reforms were actually implemented.

971. An element of the costs claimed by Western Power was for the transfer of system management functions to AEMO. As set out in the draft decision, system management functions do not form part of Western Power’s covered network services. Prior to AEMO taking on these functions, Western Power provided these services through a ring-fenced business unit and the costs were recovered through wholesale electricity market fees.

972. For the reasons set out above, the ERA considers that the costs identified by Western Power in its proposed unforeseen events adjustment were not necessary for the provision of covered services, so do not form part of Western Power’s target revenue, and would not be incurred by a service provider efficiently minimising costs. Consequently, they cannot be included as costs in an unforeseen events adjustment, regardless of whether the events that led to them were unforeseen or not.

973. Accordingly, the costs of the actions undertaken by Western Power - particularly the larger costs of preparation to move to the national regulatory regime and the transfer of system management - properly should be incurred by the State rather than imposed on customers.

Required Amendment 12

Western Power must adjust target revenue to remove its proposed unforeseen event adjustment.

Technical Rules changes

974. Western Power assessed the Technical Rules changes that occurred over AA3 and considered there was no need for an adjustment to target revenue for AA4.

975. Synergy submitted the ERA should also assess whether a reduction in target revenue is required.

976. During AA3, Western Power proposed three sets of amendments to the Technical Rules.[115] The ERA undertook a review of these proposed amendments as required under the Access Code, including conducting public consultation, and published the following decisions:

- Final Decision on Western Power's Proposed Amendments to the Technical Rules (Submitted November 2015):[116]
  - removing the limit for direct current injection (clause 3.2.1(c)(3))
  - removing out-of-date references to Australian Safety Standard AS 4777 (2005);
  - amendments to the definition of the term "connection point";
  - amendments to the definition of the term "connection asset";
  - amendments to the proposed definition of the term "point of common coupling"; and
  - amendments to the proposed correction of the wording to clause A12.2 from "National Professional Engineers' Register Standing" to "National Professional Engineers Register (NPER) or equivalent standing".
- Final Decision on Western Power's Proposed Amendments to the Technical Rules (Submitted March 2016):[117]
  - The removal of three phase faults from credible contingency scenarios for voltages at or above 66kV (i.e. the transmission system);
  - Amendments to the N-1 provisions to allow voluntary load shedding and post contingent run back generation for user agreed connections; and
  - The addition of the term "weak infeed fault conditions" to the Technical Rules Glossary and a new sub-clause to clause 2.9.4 setting out how quickly a protection relay and associated circuit breaker must clear a fault.
- Final Decision on Western Power's Proposed Amendments to the Technical Rules (Submitted April 2016):[118]
  - amendments to the wording of the Normal Cyclic Rating criterion which outlines the permissible level of power loss following the unplanned loss of a supply transformer at a substation;
  - the replacement of references to Electricity (Supply Standards and System Safety) Regulations 2001 with references to Electricity (Network Safety) Regulations 2015;
  - correction of an incorrect cross reference in Clause 4.2.1(b); and
  - correction of the misspelling of the word "Distribution" in the title of Section 5.

[115] Proposals were submitted to the ERA in November 2015, March 2016 and April 2016. These proposals are available from the ERA website at: https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules/technical-rules

[116] Economic Regulation Authority, *Western Power's Proposed Amendments to the Technical Rules Submitted November 2015: Final Decision*, July 2016.

[117] Economic Regulation Authority, *Western Power's Proposed Amendments to the Technical Rules Submitted March 2016: Final Decision*, November 2016.

[118] Economic Regulation Authority, *Western Power's Proposed Amendments to the Technical Rules Submitted April 2016: Final Decision*, November 2016.

977. As required under section 7.2.1 of the current access arrangement, Western Power included a report in its proposed revisions for AA4 setting out a description of the nature and timing of the effect of the Technical Rule change on its operating and capital expenditure during the AA3 period. The report was included as Attachment 10.7 to the Access Arrangement Information.

978. Attachment 10.7 only refers to what are described as “key changes”. The ERA compared the list of actual amendments with those identified by Western Power. Western Power incorrectly described the amendment to the Normal Cyclic Rating criterion as applying only to the CBD. It had also not included the removal of three phase faults from credible contingency scenarios for voltages at or above 66kV. The ERA considered this would be a “key change”. In any case, the report was required to include all amendments to the Technical Rules.

979. The ERA requested Western Power to amend its report to include all Technical Rule changes and to provide a more detailed assessment of the effect on expenditure, rather than just describing the effect on expenditure as “no material impact”. The revised report demonstrated the amendments had not resulted in changes to expenditure.

Deferred revenue

980. In its proposed revisions for AA2, Western Power proposed an alternative treatment of capital contributions from its approach in AA1, which had the effect of significantly increasing the revenue requirement. To avoid price shocks (as required by section 6.4(c) of the Access Code) and considering that the change in treatment of capital contributions policy should have a neutral commercial effect on Western Power’s business in present value terms, an amount of revenue was deferred from the current access arrangement period to subsequent access arrangement periods. The ERA determined the deferred revenue should be recovered over the life of the assets to which it related.

981. The values of the revenue deferred from AA2 are set out in Table 164 and Table 165 below.

Table 164 Derivation of transmission deferred revenue ($ million real June 2012)

Financial year ending:	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening deferred revenue value		69.6	75.2	81.2
Plus time value of money (AA2 Real Pre-tax WACC 7.98%)		5.6	6.0	6.5
Closing deferred revenue value	69.6	75.2	81.2	87.7

Source: Amended proposed revisions to the Access Arrangement for the Western Power Network AA3.

Table 165 Derivation of distribution deferred revenue ($ million real June 2012)

Financial year ending:	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening deferred revenue value		523.1	564.8	609.9
Plus time value of money (AA2 Real Pre-tax WACC 7.98%)		41.7	45.1	48.7
Closing deferred revenue value	523.1	564.8	609.9	658.6

Source: Amended proposed revisions to the Access Arrangement for the Western Power Network AA3.

982. An amendment to the Access Code was gazetted on 30 September 2011 to insert the following new sections as set out below:

Recovery of deferred revenue

6.5A In this Chapter, **"deferred revenue"** means the amounts referred to in paragraphs 5.37A and 5.48A of the Amended Proposed Revisions dated 24 December 2009 to the *Western Power Network access arrangement*, as approved by the *Authority's further final decision* dated 19 January 2010, expressed in present value terms as at 30 June 2009 and in real dollar values as at 30 June 2009, being respectively:

(a) $64.5 million; and

(b) $484.2 million.

6.5B An amount in respect of *deferred revenue* must be added to the *target revenue* for the *Western Power Network* for one or more *access arrangement periods* until the aggregate amount referred to in section 6.5E has been added.

6.5C An amount added to the *target revenue* under section 6.5B must include an adjustment so that the deferral of the *deferred revenue* is financially neutral for the Electricity Networks Corporation, taking into account:

(a) the time value of money; and

(b) inflation.

6.5D The *Authority* must determine the amount to be added under section 6.5B in a given *access arrangement period*.

6.5E The total of all amounts added under section 6.5B (aggregated over all *access arrangement periods* for which such amounts are added) must equal:

(a) the total amount of the *deferred revenue*;

plus:

(b) the sum of all adjustments under section 6.5C.

983. The Access Code does not prescribe over what period the revenue should be recovered, with the ERA being required to determine the amount to be added to target revenue for each access arrangement period.

984. The values of deferred revenue to be recovered in AA4 and future access arrangements are set out in the access arrangement in sections 7.7.1 to 7.7.3:

7.7.1 For the purposes of clauses 6.5A to 6.5E of the Code an amount must be added to target revenue for the distribution system in the fourth access arrangement period or subsequent access arrangement periods such that the present value (at 30 June 2012) of the total amount added to target revenue (taking account of inflation and the time value of money) is equal to $520.5 million ($ real as at 30 June 2012).

7.7.2 For the purposes of clauses 6.5A to 6.5E of the Code an amount must be added to the target revenue for the transmission system in the fourth access arrangement period or subsequent access arrangement periods such that the present value (at 30 June 2012) of the total amount added to target revenue (taking account of inflation and the time value of money) is equal to $70.5 million ($ real as at 30 June 2012).

7.7.3 The timeframe for recovering the deferred revenue amounts in section 7.71 will be 37 years and in section 7.7.2 will be 45 years.

985. The derived closing balance of deferred revenue in 2012 was used as the starting point for calculating AA3 deferred revenue payments. The annuity calculation was based on a real pre-tax WACC of 3.6 per cent. The following tables show how the deferred revenue for transmission and distribution are rolled forward over the AA3 period.

Table 166 Transmission deferred revenue roll forward over the AA3 period ($ million real June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening deferred revenue value	87.7	87.0	86.3	85.6	84.9
less principal recovered	-0.6	-0.7	-0.7	-0.7	-0.7
Closing deferred revenue value	87.0	86.3	85.6	84.9	84.2
Revenue recovered through tariffs	3.8	3.8	3.8	3.8	3.8

Source: Amended proposed revisions to the Access Arrangement for the Western Power Network AA3 Model

Table 167 Distribution deferred revenue roll forward over the AA3 period ($ million real June 2012)

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening deferred revenue value	658.6	651.6	644.4	637.0	629.3
less principal recovered	-6.9	-7.2	-7.4	-7.7	-8.0
Closing deferred revenue value	651.6	644.4	637.0	629.3	621.3
Revenue recovered through tariffs	30.7	30.7	30.7	30.7	30.7

Source: Amended proposed revisions to the Access Arrangement for the Western Power Network AA3 Model

986. Western Power included these deferred revenue amounts in its proposed target revenue for AA4. The transmission deferred revenue balance at the end of AA3 was $84.2 million in real 2012 prices. This was then indexed with actual inflation to derive an opening balance of $92.8 million in real 2017 prices for the AA4 period. The distribution deferred revenue balance at the end of AA3 was $621.3 million in real

2012 prices. This was then indexed with actual inflation to derive an opening balance for AA4, which is $685 million in real 2017 prices.

987. Western Power proposed to continue recovering the deferred revenue over the life of the assets.

988. The roll forward of these amounts from the opening of the AA4 period to the closing of the AA4 period is shown in Table 168 and Table 169 (below), along with the revenue being recovered in the AA4 period.

Table 168 Transmission deferred revenue roll forward over the AA4 period, $ million real June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening deferred revenue value	92.8	92.1	91.4	90.6	89.9
less principal recovered	0.7	0.7	0.8	0.8	0.8
Closing deferred revenue value	**92.1**	**91.4**	**90.6**	**89.9**	**89.0**
Revenue recovered through tariffs	4.8	4.8	4.8	4.8	4.8

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 234.

Table 169 Distribution deferred revenue roll forward over the AA4 period, $ million real June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening deferred revenue value	685.0	677.3	669.3	660.8	652.0
less principal recovered	7.7	8.1	8.4	8.8	9.2
Closing deferred revenue value	677.3	669.3	660.8	652.0	642.9
Revenue recovered through tariffs	**37.7**	**37.7**	**37.7**	**37.7**	**37.7**

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 234.

989. Stakeholder submissions did not comment on the recovery of deferred revenue.

990. The target revenue values for AA4 are consistent with the method and asset lives determined by the ERA in previous decisions, which the ERA accepted as being compliant with the Access Code requirements.

Tariff equalisation contributions

Access Code requirements

991. Section 6.37A of the Access Code provides for target revenue to include an amount of tariff equalisation contributions (TEC), which comprises an amount levied on users of the Western Power Network to finance amounts paid to Horizon Power for the provision of electricity services in areas not serviced by the Western Power Network.

> 6.37A If the service provider for the Western Power Network is or will be required, by a notice made under section 129D(2) of the Act, to pay a tariff equalisation contribution into the Tariff Equalisation Fund during an access arrangement period, then an amount may be added to the target revenue for the covered network for the access arrangement period, which amount—
>
> (a) must not exceed the total of the tariff equalisation contributions which are or will be required to be paid under the notice, including any amount that was payable or paid before the commencement of the access arrangement period; and
>
> (b) must be separately identified as being under this section 6.37A.

Current access arrangement

992. The TEC is included as a separate item in the pricing formula, so the value is not included in the ERA's determination. However, in the past the pricing profile has usually taken account of any forecast variations in the annual TEC values.

Western Power's proposal

993. The 2016/17 network tariffs included $150 million for the TEC. The Government gazetted a value of $167 million for the 2017/18 year on 13 June 2017. Values for future years had not been gazetted at the time of the draft decision.

994. Western Power based its proposal on the values included in the 2017 State Budget, noting that the values would be updated for the final decision.

Table 170 Western Power's initial forecast TEC for the AA4 period ($ million nominal)

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

Source: Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 233.*

Submissions on Western Power's initial proposal

995. Submissions from Change Energy, Community Electricity, and the Western Australian Council of Social Services (WACOSS) raised concerns regarding how the TEC should be reflected in network tariffs. These submissions have been considered in the section on pricing methods.

Considerations of the ERA

996. Western Power proposed to retain the TEC as a separate factor in the price control formula. The ERA accepted this on the basis that the Access Code provides for these costs to be recovered by Western Power if a notice is made under section 129D(2) of the *Electricity Industry Act 2004* for it to pay a tariff equalisation contribution.

997. As the price control formula includes a separate factor for the tariff equalisation contribution it is not necessary for the ERA to include the cost in its determination of target revenue. However, consistent with the approach taken in the past, the ERA recognises variations in the TEC from year to year will cause variations in customer bills. The ERA considered this in the section on determining target revenue and the price path.

998. In its revised proposal, Western Power has updated its revenue model to take account of values gazetted[119] for the 2018/19 TEC on 29 May 2018. The revised values are set out in Table 171 below.

Table 171 Western Power's revised forecast TEC for the AA4 period ($ million nominal)

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

Source: Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 30.

999. The ERA has updated its revenue model to reflect the revised TEC.

[119], Western Australian Government Gazette, No. 78, 29 May 2018, p. 1746.

REFERENCE AND NON-REFERENCE SERVICES

Access Code requirements

1000. Section 5.1(a) of the *Electricity Networks Access Code* 2004 (Access Code) requires that an access arrangement specify one or more reference services.

1001. A reference service is a service described in the access arrangement that includes a specified reference tariff and service standard benchmark.

1002. The requirements for reference services are set out in section 5.2 of the Access Code:

> 5.2 An access arrangement must:
>
> (a) specify at least one reference service; and
>
> (b) specify a reference service for each covered service that is likely to be sought by either or both of:
>
> (i) a significant number of users and applicants; or
>
> (ii) a substantial proportion of the market for services in the covered network;
>
> and
>
> (c) to the extent reasonably practicable, specify reference services in such a manner that a user or applicant is able to acquire by way of one or more reference services only those elements of a covered service that the user or applicant wishes to acquire; and
>
> (d) for the covered network that is covered under section 3.1 – specify one or more reference services such that there is both:
>
> (i) a reference service which enables a user or applicant to acquire an entry service at a connection point without a need to acquire a corresponding exit service at another connection point; and
>
> (ii) a reference service which enables a user or applicant to acquire an exit service at a connection point without a need to acquire a corresponding entry service at another connection point.

1003. The network covered under section 3.1 of the Access Code is the portions of the SWIS which are owned by Western Power. The SWIS is defined in section 3 of the Act as:

> … the interconnected transmission and distribution systems, generating works and associated works –
>
> (a) located in the South West of the State and extending generally between Kalbarri, Albany and Kalgoorlie; and
>
> (b) into which electricity is supplied by –
>
> (i) one or more of the electricity generation plants at Kwinana, Muja, Collie and Pinjar; or
>
> (ii) any prescribed electricity generation plant[120]

[120] The ERA is not aware of any other generation plant being prescribed.

1004. The following definitions included in the Access Code are relevant to understanding the reference services in the access arrangement:

> **"Covered service"** means a *service* provided by means of a *covered network*, including:
>
> (a) a connection service; or
>
> (b) an *entry* service or *exit* service; or
>
> (c) a network use of system service; or
>
> (d) a common service; or
>
> (e) a *service* ancillary to a *service* listed in paragraphs (a) to (d) above,
>
> but does not include an *excluded service*.
>
> {Note: This Code uses the expression *covered service* to describe what is sometimes called a "regulated service". It can be distinguished from an *excluded service*.
>
> Covered services subdivide into reference services and non-reference services.}
>
> **"Services"** has the meaning given to that term in Part 8 of the Act, and "service" has a corresponding meaning.
>
> {Note: At the time the Electricity Networks Access Code Amendments (No 2) 2008 were made,[121] the definition in section 103 of the Act was:
>
> "**services**" means –
>
> (a) the conveyance of electricity and other services provided by means of network infrastructure facilities[122]; and
>
> (b) services ancillary to such services.}
>
> **"Connection service"** means the right to connect facilities and equipment at a connection point.
>
> {Note: A *connection service* is the right to physically connect to the network, and will regulate technical compliance etc. It is not the same thing as an *entry service* or *exit service*, which are the right to transfer electricity.}
>
> **"Entry service"** means a covered service provided by a service provider at an entry point under which the user may transfer electricity into the network at the entry point.
>
> **"Exit service"** means a covered service provided by a service provider at an exit point under which the user may transfer electricity out of the network at the exit point.
>
> **"Common service"** means a *covered service* that is ancillary to the provision of one or more of *entry services*, *exit services* and network use of system services that ensures the reliability of a *network* or otherwise provides benefits to *users* of the

[121] The definition in section 103 of the Act has not changed, as at the date of this decision.

[122] Network infrastructure facilities is defined in section 103 of the Act as the electrical equipment that is used only in order to transfer electricity to or from an electricity network at the relevant point of connection including any transformers or switchgear at the relevant point or which is installed to support or to provide backup to that electrical equipment as is necessary for that transfer; and the wires, apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity which together are operated by a person (a network service provider) for the purpose of transporting electricity from generators of electricity to other electricity networks or to end users of electricity.

network, the costs of which cannot reasonably be allocated to one or more particular *users* and so needs to be allocated across all *users*.

"Excluded service" means a service provided by means of a covered network, including:

(a) a connection service; or

(b) an entry service or exit service; or

(c) a network use of system service; or

(d) a common service; or

(e) a service ancillary to a service listed in paragraphs (a) to (d) above,

which meets the following criteria:

(f) the supply of the service is subject to effective competition, and

(g) the cost of the service is able to be excluded from consideration for price control purposes without departing from the Code objective.

"Reference service" means a covered service designated as a reference service in an access arrangement under section 5.1(a) for which there is a reference tariff, a standard access contract and service standard benchmarks.

"Non-reference service" means a covered service that is not a reference service.

"Reference tariff" means the tariff specified in a price list for a reference service.

1005. The designation of any service as an excluded service is subject to determination by the ERA under section 6.33 of the Access Code. Other than as determined by the ERA under this section, all services provided by means of the covered network are covered services.

Current access arrangement

1006. Section 2.2 of the current access arrangement includes the following reference services:

- Anytime Energy (Residential) Exit Service, A1
- Anytime Energy (Business) Exit Service, A2
- Time of Use Energy (Residential) Exit Service, A3
- Time of Use Energy (Business) Exit Service, A4
- High Voltage Metered Demand Exit Service, A5
- Low Voltage Metered Demand Exit Service, A6
- High Voltage Contract Maximum Demand Exit Service, A7
- Low Voltage Contract Maximum Demand Exit Service, A8
- Street lighting Exit Service (including streetlight maintenance), A9
- Un-Metered Supplies Exit Service, A10

- Transmission Exit Service, A11
- Distribution Entry Service, B1
- Transmission Entry Service, B2
- Anytime energy (residential) bi-direction service, C1
- Anytime energy (business) bi-direction service, C2
- Time of Use (Residential) – bi-direction service, C3
- Time of use (business) bi-directional service, C4

1007. The current access arrangement does not specify any services as excluded services.

Western Power's initial proposal

1008. In its initial proposal, Western Power proposed to retain all of the reference services included in the current access arrangement, with amendments to four services:

- High Voltage Metered Demand Service, A5
- Low Voltage Metered Demand Service, A6
- High Voltage Contract Maximum Demand Service, A7
- Low Voltage Contract Maximum Demand Service, A8.

1009. Western Power proposed deleting "exit" from the high and low voltage reference services to allow bi-directional flows. This would enable such customers to have behind-the-meter generation such as solar photovoltaics (PV).

1010. Western Power also proposed modifying the peak/off peak time for the high voltage and low voltage metered demand services (A5 and A6).

1011. Currently, the A5 and A6 peak time periods are weekdays 8:00 AM to 10:00 PM. Western Power proposed changing the A5 peak time to weekdays 3:00pm to 9:00pm. It proposed changing the A6 peak time to 3:00pm to 9:00pm on weekdays and weekends.

1012. In addition, Western Power proposed to introduce four new reference services:

- Time of use energy (residential) service, D1
- Time of use energy (business) service, D2
- Time of use demand (residential) service, D3
- Time of use demand (business) service, D4.

1013. Western Power stated:

> These services will be provided to all residential and small business customers requesting[123] a new meter as advanced meters will now be installed as standard. The new tariffs that correspond to these new services better reflect the costs incurred by

[123] Where Western Power installs an advanced meter for compliance reasons, the customer may choose to opt-in to these new services.

> Western Power in providing reference services and will provide price signals to customers regarding the most efficient times to use the network.
>
> Western Power has consulted with customers, retailers and the State Government to develop these services. These new time of use reference services will provide customers with the best opportunity to manage their own consumption in an efficient and cost effective manner. Our aim is to encourage customers to change their consumption patterns (where practicable) by shifting their electricity use to off peak times. This would potentially decrease their electricity bills and also allow Western Power to reduce investment in the network to accommodate peak demand.[124]

1014. Western Power also proposed amendments to its description of reference services offered, which is set out in Appendix E of the access arrangement, including the eligibility criteria, reference tariff, service level and applicable contract for each service. The proposed changes were primarily to reflect the new and amended reference services described above and additional or amended definitions and eligibility requirements for existing reference services.

1015. Western Power's access arrangement information noted that, where a customer requested a non-standard service, it can develop a customised product as a non-reference service. Examples of non-reference services currently provided by Western Power include:[125]

- processing and administration fees for an application for network access as detailed in the applications and queuing policy;
- network access services with conditions that vary from reference services; and
- all other services that are not core to the transport of electricity from the supplier to the end-use customer, including, for example the elevation of overhead lines to allow the transport of high loads and the provision of pre-payment metering services.

1016. Western Power proposed that non-standard services provided under non-reference service contracts would not be listed or priced other than in the contract and would not have minimum service standards provided.[126]

Submissions on Western Power's initial proposal

1017. Submissions on Western Power's initial proposal relevant to reference services were received from AGL, Alinta Energy (Alinta), Bluewaters Power, Community Electricity, Synergy, and Perth Energy.

1018. Details of matters raised in the submissions are included below under "Considerations of the ERA".

[124] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 81.

[125] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 83.

[126] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 83.

Considerations of the ERA

1019. This section focuses on the services offered. The structure and pricing of services is considered under Pricing Methods, Price List and Price List Information.

1020. The ERA's considerations are set out below in the following order:

- Identification of reference services required.
- Western Power's proposed new reference services.
- Western Power's proposed amended reference services.
- Metering services.
- Additional reference services proposed by users.
- Other amendments to reference services.
- Non-reference services.

Identification of reference services required

1021. Western Power must specify a reference service for each covered service that is 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.

1022. The "users" of Western Power's network are predominantly retailers, generators and large users with direct connections to the transmission system. As set out below, many of these users did not consider Western Power had adequately determined the services they require.

1023. Submissions from AGL, Alinta, the Australian Energy Council, Community Electricity and Synergy on Western Power's initial proposal all raised concerns that Western Power had not adequately determined the services users - retailers and directly connected customers - require.

1024. As set out below, AGL, the Australian Energy Council and Community Electricity raised concerns that Western Power's consultation with retailers who use the reference services was inadequate, and it has consulted inappropriately with residential and business consumers who are customers of the retailers, not Western Power.

1025. AGL submitted:

> Western Power is a service provider to the retailers in the WEM, and therefore should be focussed on meeting the connection needs of the retailers, who in turn have the relationship with the customers.[127]

1026. The Australian Energy Council questioned whether:

> … existing or prospective retailers have been adequately engaged to determine their reference service requirements. For example, to what extent has Western Power historically modified or introduced new reference services directly in response to retailer requests?

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[127] AGL submission, p. 4.

1027. Community Electricity submitted:

> We suggest that the majority of customers consulted actually thought they were talking to Synergy, their retailer. We suggest that the Western Power side of the conversation did not know that there are other retailers in competition to Synergy and which have to be treated equitably to Synergy. We question the probity of loosing Western Power on customers (with whom they have no ETAC) without a retailer chaperone. We were not informed if Western Power interfered with any of our customers.
>
> …
>
> Insofar as we were consulted as a retailer, our advice has been entirely ignored.

1028. Synergy considered Western Power had not provided the reference services it required:

> Reference services should provide a fundamental mechanism to "…promote competition in markets upstream and downstream of the networks" in accordance with the Code objective.
>
> In the case of retail markets, the extent to which reference services provide retailers with the ability to develop customer offerings that meet their commercial interests and those of their customers is key to determining how well the reference service satisfies the Code objective. WP's proposed reference services do not achieve this, in part because the eligibility criteria for these services requires that they are only available in circumstances where an electricity transfer access contract between WP and a user is not materially different to the standard access contract approved by the Authority for AA4. In Synergy's view, this may operate to prevent a user with a negotiated electricity transfer access contract from obtaining reference services. Such an outcome may amount to a breach of section 4.34 of the Code which requires that the revised access arrangement must not override prior contractual rights.
>
> In Synergy's view the Code objective will be poorly served if retailers are forced to use services or are offered services that do not underpin customer offerings. In light of our customer research and customer demand for affordability, behind the meter and distributed generation solutions, Synergy (a significant user) considers its proposed reference services better achieve the Code objective and will provide the basis to develop customer offerings that are likely to be sought by a substantial proportion of the market.
>
> The provision of network services that reflect user requirements is an essential base for users to develop and offer products and services that meet their customers' requirements. More dynamic network tariff structures are needed compared to what currently exist to address the changing consumption patterns and consumer expectations brought on by emerging technologies. Put simply, limited network services limit the capacity for retailers to offer new electricity retail products that meet the needs and preferences of their customers. This is reflected in WP's annual planning report 2017 in which WP sees itself as "acting as a platform for business and residential customers to choose how they want their electricity supplied and delivered".

1029. Synergy advised that none of its requested reference services had been included in Western Power's initial proposal.

1030. Synergy expressed concern that there is no mechanism in Western Power's proposed revised access arrangement to determine which services a significant number of users or a substantial proportion of the market wants:

> Under WP's current proposal any request for a service by a user or applicant will be treated as a request for a non-reference service. This approach compels a network user to negotiate with WP for a non-reference service required by that network user, granting WP the ability to access a potentially significant source of revenue without the need for independent regulatory determination by the Authority. In Synergy's view, this arrangement is inconsistent with the Code objective because it gives WP the ability

> to use its monopoly position in an unconstrained manner, contrary to economic efficiency. It is also an outcome that is inconsistent with the matters to which the Authority is required to have regard under section 26(1) of the *Economic Regulation Authority Act 2003* (WA) (ERA Act).

1031. In the draft decision, the ERA agreed with the views expressed in submissions that Western Power should base its reference services on users' requirements, rather than basing them on what Western Power thinks users require. The Access Code clearly states that a reference service should be specified for covered services *likely to be sought by users*.

1032. The ERA's considerations of the additional reference services proposed by users is set out below in paragraph 1164 onwards.

Proposed new reference services

1033. Western Power's proposed new reference services in its initial proposal were based on customers having advanced meters installed:[128]

> Western Power's change to advanced meters as the standard meter … enables new services to be introduced which give customers greater control over their electricity bills, and also help Western Power mitigate the need for costly capital investment to address the peak demand on the network. We propose to introduce four new reference services that are enabled by advanced meters:
>
> - D1 - Time of use energy (residential) service
> - D2 - Time of use energy (business) service
> - D3 - Time of use demand (residential) service
> - D4 - Time of use demand (business) service.
>
> These services will be provided to all residential and small business customers requesting a new meter as advanced meters will now be installed as standard. The new tariffs that correspond to these new services better reflect the costs incurred by Western Power in providing reference services and will provide price signals to customers regarding the most efficient times to use the network.
>
> Western Power has consulted with customers, retailers and the State Government to develop these services. These new time of use reference services will provide customers with the best opportunity to manage their own consumption in an efficient and cost effective manner. Our aim is to encourage customers to change their consumption patterns (where practicable) by shifting their electricity use to off peak times. This would potentially decrease their electricity bills and also allow Western Power to reduce investment in the network to accommodate peak demand.

1034. As set out in the section on forecast capital expenditure, the ERA's draft decision did not approve Western Power's proposed expenditure for the roll-out of communications for advanced meters. Western Power did not adequately demonstrate that the proposed expenditure meets the new facilities investment test. The ERA noted that Western Power might want to reconsider its proposed new reference services in light of the ERA's draft decision on advanced metering expenditure.

[128] Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 81.

1035. In its initial proposal, Western Power submitted that the purpose of a time of use tariff is to encourage customers to spread their electricity use over the course of the day. Western Power noted that currently residential customers tend to use the most electricity between 3:00 PM and 9:00 PM on a weekday:[129]

> Typically, people arrive home from school and work, switch on the oven, turn on the TV, do the laundry, and often use several electrical appliances. This means a lot of electricity is being distributed throughout the network at the same time, particularly on the hottest summer days when many people return home to a hot house and begin using their air conditioning. We call this time the network peak.
>
> Generally, as the population grows the network peak gets higher, which means the network must be able to cope with more and more electricity running through it. To make sure the network can cope with the peak (and so customers don't lose power), Western Power needs to reinforce and increase the capacity of the network.
>
> With a new substation costing around $45 million, investment in increasing network capacity is very expensive. It is also worth noting that the highest peaks of network demand only occur a few times per year, so the cost of increasing peak network capacity is disproportionate to the amount of time the additional capacity is required.
>
> Time of use network tariffs are a potential alternative to the costly option of increasing network capacity. By encouraging customers to use electricity outside of peak times, the tariffs can help reduce the need for network capacity expansion, which saves customers money over the long term.
>
> Time of use tariffs can assist customers to reduce their bills. A trial of time of use tariffs for 750 Perth households in 2011 and 2012 found that by just making a few moderate changes – washing at a different time, running the pool pump overnight, using the air-conditioning on a timer – customers saved up to $50 per annum.
>
> Time of use network tariffs can also benefit small business customers, particularly where the business is able to adjust its electricity consumption patterns. Western Power already offers a time of use tariff (RT4 Time of Use Energy) to businesses, with about 14 per cent of small businesses currently connected to the network already on the RT4 tariff. The current RT4 tariff has a peak/off peak charging window of 8:00 AM to 10:00 PM on weekdays. While the RT4 tariff is beneficial to customers who can shift their electricity usage to outside these times, the peak charging window is too large to accurately reflect network peak times and encourage electricity usage outside of the typical late afternoon/early evening peak demand period.
>
> Therefore Western Power proposes new time of use network tariffs for small businesses and residential customers that better reflects peak demand times. The new tariff charges a higher rate on weekdays between 3:00 PM and 9:00 PM, and a lower rate between 9:00 PM and 12:00 AM. Customers on existing time of use network tariffs will have the option of moving to these new tariffs.
>
> As more customers take up time of use tariffs, system peaks should not grow at the same rate, reducing the need for costly peak capacity investment over the long-term.
>
> A time of use network tariff requires customers to have advanced meters (or at least electronic or interval meters).

1036. Western Power described its proposed demand-based service as follows:[130]

> Demand tariffs are similar to time of use tariffs, however a demand tariff considers a customer's maximum usage in any one 30 minute period rather than total consumption

[129] Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, pp. 251-252.

[130] Western Power, Access arrangement information: Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 252.

> over a time period. This sends a much stronger signal about the impact customer behaviour can have on the overall system peak.
>
> As this is the first time residential customers will be offered this type of tariff, it is being offered on an opt in basis only and will have a very small demand component to begin with to allow time for customers to understand the impact of this type of charge. This type of tariff is only possible due to the introduction of advanced meters, which allow for much more data to be captured than via a traditional meter.
>
> The initial tariff offering will charge the same tariff components of the time of use tariffs described above, albeit at a slightly reduced rate, with an additional component for the maximum demand in the peak window of 3:00 PM to 9:00 PM.

1037. In its initial proposal, Western Power advised that rates for the new reference services were to be set so that the average customer would pay the same under a flat rate, time of use or demand-based tariff.

1038. In the draft decision, the ERA identified the following matters that needed to be considered in evaluating Western Power's proposed new reference services:

- Are the services likely to be sought by users?
- Should the new services should be mandatory?

Are the services likely to be sought by users?

1039. As discussed above, the users of the network are retailers, generators and large customers directly connected to the transmission network. Consequently, network tariffs do not necessarily provide a price signal to end-use customers, but rather a price signal to users.

1040. In its submission on Western Power's initial proposal, Kleenheat was supportive in principle of the new reference services but:

> …questions whether Western Power sufficiently "appreciates the ever-changing patterns of customer demand and technologies to design suitable tariffs and the implications for competitive neutrality between retailers.

1041. ERM Power and Community Electricity considered that modifying network tariffs would have little effect if retail tariffs did not change.

1042. ERM Power:

> … while Western Power is proposing differing tariff structures, Western Power does not bill the end use customer, Synergy does. Unless residential tariffs are restructured in such a manner that will allow the benefits of smart meters to flow through, is it too early for Western Power to embark on this measure?

1043. Community Electricity:

> We consider that the proposed initiative - metering & tariffs - is inappropriate because its effectiveness is contingent on the introduction of retail price signals, which is a government decision outside the authority of Western Power and Synergy. Network design also needs to recognise that bi-directional flows are of increasing importance while the proposed signals are uni-directional only.
>
> The practical reality is that the structure of the existing retail tariffs has remained the same over the last 20+ years and the government has recently committed to price increases under the existing structures as a means of budget repair. Further, insofar as time of use tariffs were to be introduced, customers would respond to the holistic price signal without perceiving the network structure that contributes to it. In particular, the wholesale market capacity charge would dominate the price signal, making the

> impact of customer response to Western Power's cashflows unpredictable and likely to spawn unintended consequences through unbalancing revenues and costs.

1044. Synergy supported sending cost reflective price signals to customers via time of use reference services and providing customers with a range of opt in choices. However, Synergy considered Western Power’s proposed time of use reference services were too limited and did not promote the efficient use of the network. It considered that offering a range of time of use network services with cost reflective price differentials would allow for services that are better aligned with the diverse needs of electricity consumers:

> Multiple network services provides network users with greater choice and flexibility to create retail products that meet the needs of their customers, as opposed to a one size fits all approach. Although take up rates of time of use retail tariffs are historically low, Synergy considers voluntary uptake can be encouraged through a combination of reference service choice (that facilitates retail tariff choice), embedded generation, advanced energy efficiency, consumer engagement and education.

1045. Synergy also considered the transition to new tariffs would need to be supported by the up-take of enabling technologies as consumers seek to manage their electricity costs using demand side technologies such as solar, storage and efficient appliances:

> More dynamic tariff structures are needed to address the changing consumption patterns and consumer expectations brought on by emerging technologies rather than a one size fits all approach. Forecasts indicate increasing uptake of electric vehicles (EVs) in coming years and Synergy’s proposed time of use references services are specifically aimed at promoting such uptake in the SWIS. Notwithstanding future growth, EVs have the potential to increase peak period demand if not addressed with appropriate tariff structures.

1046. Synergy proposed alternatives to Western Power’s new time of use and demand reference services. These are considered below under reference services proposed by users.

1047. In the draft decision the ERA considered Western Power’s proposed new reference services should be assessed on the merits of price signals to retailers. Retailers have many opportunities to influence customers' use of energy, such as retail pricing structures and customer education. Network reference services should promote competition by giving retailers the opportunity to be innovative in the prices and services they offer to customers.

1048. The ERA considered there was likely to be a demand for a time-of-use service, and that demand might increase if there was deregulation of the market for small-use customers. In any case, providing users retain the ability to obtain the flat rate service, introducing the time-of-use service would not result in any adverse consequences for users.

Should the proposed new reference services be mandatory?

1049. In its initial proposal, Western Power proposed that all new residential and commercial customers would be on the new time of use reference service with the option to select the new demand reference service.

1050. Submissions from AGL, Alinta, the Australian Energy Council and Kleenheat on Western Power’s initial proposal considered the network operator should not be able to unilaterally determine the service to be provided.

1051. AGL submitted:

> … it is not for the network operator to unilaterally determine the service that should be provided to a customer, as this is a matter to be negotiated and agreed between the retailer and customer. In the NEM, there is no mandatory linking by the network operators between the customer's meter and tariffs as network tariffs are a feed in, and should not drive a retailer and its customer's selection of a retail product.

1052. Alinta and the Australian Energy Council noted it is standard in the National Electricity Market (NEM) for customers to be able to opt in or opt out of time of use transport charges.

1053. Kleenheat considered the new reference services should be on a voluntary opt-in basis rather than the mandated requirement that Western Power proposed. It considered mandating new tariffs to be inconsistent with the Access Code objective of promoting competition and inconsistent with the matters the ERA must consider as principles under section 26 of the *Economic Regulation Authority Act 2003*.[131]

1054. Kleenheat also considered mandating the proposed new reference services would make it difficult for retailers to design and innovate with their own retail tariffs:

> Kleenheat considers time of use tariffs are likely to affect the bundled electricity contracts that non-Synergy retailers have traditionally offered to contestable customers which could "thwart full retail contestability and retailers' ability to differentiate product offerings to win customers when competition is introduced."
>
> Kleenheat contends it is difficult to assess the options retailers have to ensure cost recovery with the mandated approach of the proposed tariffs and their associated design of time of use periods. It is understood that in 2018/19, Western Power will charge users a uniform price across the three time of use periods, however there is no price visibility for the remaining four years under AA4. Kleenheat requests that the ERA seek further information in its review and approval of Western Power's AA4 to ensure retailers can fully inform themselves of how its customers and their consumption may be modelled to ensure cost recovery is viable under the proposed new tariffs.
>
> The mandated Time of Use tariffs and the mandatory new meter change over to advanced meters (known as Type Four meters) for contestable customers who churn away from Synergy, means that non-Synergy retailers are at a competitive disadvantage relative to Synergy. Synergy's position as the incumbent retailer to contestable customers (since market disaggregation) means that these customers can remain on the "anytime" network tariff. As a consequence, if these customers are to churn away from Synergy they, or the retailer, will be required to incur the cost of a new meter. If these customers remain with Synergy they will not incur the cost of a new meter. Competing retailers will either need to absorb this cost disadvantage or pass this cost of a new mandated meter onto their new customer. This policy of mandating the new tariffs with a compulsory replacement of the meter is not competitively neutral to non-Synergy retailers and will frustrate competition. As a consequence, this issue is a major concern.
>
> Unless other competition protections, such as mandating Synergy only offer customers electricity in line with regulated tariffs, are implemented with FRC, Kleenheat does not believe that the mandatory approach is fair and reasonable or appropriate to foster effective competition.

[131] To ensure that regulatory outcomes are in the public interest as well as have regard for the long-term interests of consumers, in relation to the price, and quality of services provided in the relevant markets for which the ERA has oversight.

1055. Synergy did not support mandating time of use reference services, especially in situations where the retail tariffs are similarly not mandated.

1056. The access arrangement must specify a reference service for each covered service likely to be sought by a significant number of users or a substantial proportion of the market for services.

1057. In the draft decision, the ERA had no concerns with Western Power specifying the meter type required for a user to be eligible for a particular reference service. However, users should not be restricted to a particular reference service simply because Western Power has decided to install a particular type of meter.

1058. Retailers should have choice between an anytime use or time of use tariff for both new and existing customers. Providing Western Power sets its network tariffs to recover costs, it should be indifferent to which service retailers select.

1059. If Western Power wants a higher take-up of the time of use services, it is open to Western Power to set the terms and reference tariffs to make the services attractive to users.

1060. In the draft decision, the ERA was satisfied there was likely to be a demand for the new time of use services. However, the ERA considered mandating reference services was not consistent with the Access Code objective of promoting competition or the principles under section 26 of the *Economic Regulation Authority Act 2003* regarding the interests of consumers. Western Power was required to remove the mandatory requirement for the proposed new time of use services.

1061. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 13**
>
> The proposed new time of use reference services must not be mandatory.

Western Power's revised proposal

1062. In its revised proposal, Western Power states it has accepted draft decision required amendment 13. Western Power submits:[132]

> It is clear from the ERA and stakeholders' feedback that mandatorily implementing these reference services was not well supported.
>
> 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.
>
> 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.
>
> 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

[132] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 140.

> 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.
>
> 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.
>
> 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.

1063. The proposed new time of use services are the same as proposed in Western Power's initial proposal but they have been renamed as follows:

- D1 – 3 Part Time of Use Energy (Residential) Service
- D2 – 3 Part Time of Use Energy (Business) Service

1064. The "3 Part" refers to the fact there are three time periods:

- **Off-peak** – 12:00 am to 12:00 pm and 9:00 pm to 12:00 am Monday to Friday and all times on Saturday and Sunday
- **Shoulder –** 12:00 pm to 3:00 pm Monday to Friday
- **On-peak** – 3:00 pm to 9:00 pm Monday to Friday

Submissions on the draft decision

1065. Submissions on the draft decision relevant to draft decision required amendment 13 were received from the Australian Energy Council, Synergy and Vector.

1066. The Australian Energy Council submitted that the required amendment addressed its members' concerns about mandating the service but it did not clarify whether, and if so how, differential pricing will apply to different time of use bands.[133]

1067. Synergy submitted support for the amendment and agreed with the statements in the draft decision that users should not be restricted to a particular reference service simply because Western Power had decided to install a particular type of meter.[134]

1068. Vector noted the draft decision emphasised the importance of user choice and negotiated outcomes under the Access Code.[135]

Considerations of the ERA for final decision

1069. The ERA is satisfied Western Power has complied with draft decision required amendment 13.

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133 Australian Energy Council, 13 June 2018, p. 3.

134 Synergy submission on draft decision, June 2018, p. 8.

135 Vector, 14 June 2018, p. 2.

1070. Western Power states it has formed the view that there does not appear to be a significant demand for the introduction of time of use based demand services as reference services. However, submissions from Kleenheat, Synergy, Mr Hosking, Emergent Energy, Energy Networks Australia and Change Energy on Western Power's initial proposal indicated significant support for such a reference service.

1071. Synergy is the only retailer that can supply residential and business customers using less than 50 MW of energy each year, so would be the main user for the proposed demand service. Kleenheat and Change Energy are both retailers in the contestable market – that is customers who use greater than 50 MW each year – so would be able to use it for some of their customers. Consequently, the ERA considers the service is sought by a significant number of users and a substantial proportion of the market, and requires Western Power to reinstate its proposed time of use based demand service as a reference service to satisfy the requirements of section 5.2(b) of the Access Code.

Required Amendment 13

Western Power must reinstate its proposed residential and business time of use based demand services in its proposed reference services.

1072. The pricing of the new reference services (D1 and D2) is considered under Pricing Methods, Price List and Price List Information.

Other matters raised in submissions

1073. Although Change Energy supported demand-based tariffs, it considered time of use tariffs for residential customers would lead to revenue shortfalls for Western Power as more customers adopt solar PV. It recommended increasing fixed charges for all customers if demand-based tariffs cannot be implemented:

> Demand based tariffs for both residential and business customers more accurately reflect customers' contributions to the cost of the network and will also incentivise better utilisation of the grid.
>
> We do not support moving to time of use tariffs for residential customers. Tariffs with higher peak charges will be at risk of causing large revenue shortfalls for WP as more and more customers adopt solar PV. Further it does not accurately reflect the costs of the network evenly between solar PV and non-solar PV customers.
>
> Where demand based tariffs are not practical or available, increased fixed charges should be implemented to reflect the cost of connecting and servicing a residential customer given the costs are the same whether or not solar PV has been installed.

1074. Regardless of whether the new reference services are mandated or not, users (i.e. retailers) require sufficient information to enable them to understand the effect of the new services and plan accordingly.

1075. Alinta and the Australian Energy Council noted Western Power's proposed prices for 2018/19 are identical for all time bands and that there is no information on the price path beyond 2018/19. They submitted this makes comparisons with existing tariffs difficult.

1076. Synergy also submitted that customers need to have an understanding of their energy usage and what the financial effect of moving to a new tariff is likely to be to enable them to make an informed decision. Most customers currently are only provided with two-monthly cumulative meter readings. Synergy considered more detailed information would be required:

> Interval energy data[136] provision is critical as a precursor to customers moving off anytime energy tariffs as it is unrealistic to expect customers to make a “leap of faith” to opt into a time of use retail tariff without first knowing what their consumption patterns are, or knowing what the financial impact will be prior to changing retail tariffs. Synergy expects customers will typically require at least a year’s worth of interval energy data before changing tariffs. During that time retailers can continually engage with their customers to receive feedback and learn about their consumer experiences to ensure their products and services are fit for purpose.

1077. Mr Noel Schubert argued that education programs would be required to support customers’ understanding and responses to the proposed new reference services.

1078. In the draft decision, the ERA agreed users are likely to require consumption data to assist them to understand the effect of the new reference services. It would also be in Western Power’s interests to encourage take-up of the new reference services by making metering data available on a cost reflective basis. This is discussed below under metering services.

1079. CdL Advisory expressed concerns regarding the effect of time of use tariffs on the health of older people vulnerable to heat stress:

> While WP customers have responded positively to potential time of use tariffs it is understood this is more favourable among younger customers, and is predicated on customers being well informed of the benefits. How therefore, will WP ensure that time of use tariffs do not impact on an aging population (particularly lower socioeconomic households) vulnerable to heat stress exacerbated by climate change. Research by the RMIT University has found older, less financially secure households are generally more likely to ration cooling device use during a heatwave particularly if public messaging urges conservation. RMIT also found that electronic billing and direct debit arrangements may undermine energy literacy aims.

1080. Mr Schubert, who supported the proposed new services, submitted that customers who need assistance to pay electricity bills should be supported by programs that are separate from electricity tariffs so that new electricity tariffs can deliver the improved outcomes that are available.[137]

1081. In the draft decision, the ERA agreed the matters raised by CdL Advisory and Mr Schubert are important points and would need to be dealt with for a successful implementation of the proposed new reference services. However, they are matters relevant to retail electricity charges, not network charges, and hence fall outside the remit of the ERA in making its decision on Western Power’s proposed revisions to its access arrangement.

Proposed amended reference services

1082. In its initial proposal, Western Power proposed expanding the high voltage and low voltage metered demand (A5 and A6) and contract maximum demand (A7 and A8)

[136] Energy consumed in each 30 minute period.

[137] Mr Noel Schubert, *Submission re: Proposed Revisions to the Western Power Network Access Arrangement – AA4*, 11 December 2017, p. 1.

reference services to allow bi-directional flows of electricity and amending the time periods to be consistent with its proposed new reference services.

1083. Western Power noted the current service only allows for a one-way flow of electricity. It stated it had received:

> … numerous requests from retailers to create a variation of these reference services that allow for bi-directional flows. This is largely driven by the increase in installations of solar photovoltaic systems by commercial customers.

1084. The proposed amendments to Appendix E to the access arrangement restricted the size of the PV system to 1 Mega Volt Amp (MVA). This is the same size as permitted under the current business bi-directional services (C2 and C4) for connection on the low voltage network.

1085. No submissions on Western Power's initial proposal commented on the proposal to expand the A5 to A8 reference services to include bi-directional services. As the ERA did not receive any objections from users and Western Power noted numerous requests from retailers for the service, it accepted this amendment in the draft decision.

1086. Currently the high voltage and low voltage metered demand (A5 and A6) peak time periods are weekdays 8:00 am to 10:00 pm. In its initial proposal, Western Power proposed changing the high voltage peak demand time period to weekdays 3:00 pm to 9:00 pm and the low voltage peak demand time period to 3:00 pm to 9:00 pm on weekdays and off-peak at all times on weekends.

1087. Alinta commented:

> Alinta notes that this is the first change to the structure of existing metered demand tariffs for some time and acknowledges that tariff structures need to evolve over time to meet changing needs. Noting this, many of the customers on these tariffs are likely to be on pass-through contracts. As such, these changes will affect them directly and Alinta considers Western Power will have a vital role to play in communicating these amendments.

1088. As set out in the draft decision, generally the ERA would be concerned by unilateral amendments to an existing reference service. However, in this case, the amendments appeared to be advantageous to users as Western Power reduced the peak period time. On this basis, and as no objections were submitted by users, the ERA considered the proposed amendment would still result in the service being required by a significant number of users.

1089. Further consideration of the structure and pricing of the A5 to A8 services is included in Pricing Methods, Price List and Price List Information.

Western Power's revised proposal

1090. In its revised proposal, Western Power has amended its proposal to expand the existing A5 to A8 services to include bi-directional supplies and instead has added new bi-directional reference services C5 to C8. It has retained the revised peak period for A5 and A6 as set out in paragraph 1086 above.[138]

[138] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, Western Power revised proposal, p. 146.

1091. Western Power has also amended its initial proposal by restricting the current time of use residential and business services[139] to existing customers. It states new customers may use the new 3 Part Time of Use Energy (Residential) Service D1 and 3 Part Time of Use Energy (Business) Service D2 if they require a time of use service.[140]

Submissions on draft decision

1092. Synergy submitted it was "pleased with allowing bi-directional flows for the metered demand and contract maximum demand services (A5, A6, A7, A8), noting also the peak times metered demand services have been reduced from 14 hours to 6 hours".[141]

1093. Synergy also submitted that the A1 to A4 exit services should be consolidated with the C1-C4 bi-directional services, similar to Western Power's expansion of the A5-A8 services to include bi-directional services discussed in paragraph 1090 above.

> Synergy considers this to be a positive and efficient outcome because retailers do not have to undergo the administrative burden of re-nominating services if a customer, under those services, installs PV generation.

Considerations of the ERA

1094. The ERA sought an explanation from Western Power of why it had decided not to make the metered demand and contract maximum demand reference services, A5-A8, bi-directional as proposed in its initial submission and instead had created new bi-directional reference services (C5 to C8). Western Power advised:[142]

> It should be noted that under AA3, the services A5 to A8 are Exit Services only, most retailers have adopted a non-reference version of this service unofficially designated C5-C8. The intention in the initial submission was to bring these customers on to A5 to A8 and allowances were made in the eligibility criteria for bi-directional metering as well as inverter requirements.
>
> In responding to the draft decision, significant effort went into clarifying how reference services fit alongside the metering framework. One of the outcomes was that in clearly defining the standard metering services a customer was receiving with each reference service, the concept of a uni-directional vs bi-directional meter was needed. At the same time, we were forced to more carefully think about any pricing implications of the proposed changes. With a blended exit/bi-directional service the metering service is less clear and could potentially require either kind of meter. If a customer on A5 as an exit point were to install PV, they remain eligible for A5 as a bi-directional point however do not have appropriate metering as they only have uni-directional metering. Under the initial proposal, Western Power would have two choices: upgrade the uni-directional metering to bi-directional 'for free' or request the customer pays a fee. Under the initial submission model, there is no ability to 'force' the customer to pay as they can argue they are already eligible for the service. By splitting out a separate service (C5 to C8) it is clearer that the customer is not eligible for a service until the

[139] These comprise the Time of Use Energy (Residential) Exit Service A3, Time of Use Energy (Business) Exit Service A4, Time of Use (Residential) Bi-directional Service C3 and Time of Use (Business) Bi-directional Service C4.

[140] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, Western Power revised proposal, p. 146.

[141] Synergy submission on draft decision, June 2018, p. 8.

[142] Western Power email 16 August 2018.

> metering has been upgraded. This helps ensure that any metering costs are cost reflective and attributable to the customer responsible for the costs.
>
> Note that D1 and D2 do feature a blended exit/bi-directional service however by limiting these to customers with an AMI meter, there are no additional meter upgrade costs as an AMI is already capable of both.

1095. The ERA considers Western Power's proposed amendment illustrates the importance of clearly specifying the metering service for each reference service. The ERA agrees the minimum metering requirement differs for the existing exit only A5-A8 services and the proposed new bi-directional C5-C8 services. A bi-directional meter is required for the C5-C8 bi-directional services but not for the A5-A8 exit only services. The ERA agrees introducing the proposed new reference services, rather than expanding the existing reference services, is reasonable given that the standard of meter for the bi-directional service is greater than for an exit only service and that retailers will be required to pay for a new meter, if the existing meter is not capable of bi-directional readings, to obtain a bi-directional service.

1096. The ERA considers similar issues would prevent the consolidation of the A1-A4 and C1-C4 services suggested by Synergy.

1097. As set out in the draft decision, generally the ERA would be concerned by unilateral amendments to an existing reference service. However, in this case the amendments the A5-A8 services appear to be advantageous to users as Western Power has reduced the peak period time. On this basis, and as no objections were submitted by users, in the draft decision the ERA considered the proposed amendment would still result in the service being required by a significant number of users. No objections were submitted by users on the draft decision.

1098. The ERA sought an explanation from Western Power of why it had proposed to make the Time of Use Energy (Residential) Exit Service A3, Time of Use Energy (Business) Exit Service A4, Time of Use (Residential) Bi-directional Service C3 and Time of Use (Business) Bi-directional Service C4 only available to existing customers. Western Power advised:[143]

> One of the key drivers in moving customers towards a time of use tariff is to signal the key periods of congestion on the network to encourage efficient usage of the network and, ideally, increase utilisation of the network. The services referenced are all services linked to a time of use tariff, albeit a time of use tariff that is not meeting the requirements of sending efficient signals. The peak period for these tariffs is 14 hours, which is not targeted and therefore does not help facilitate efficient network usage. The new services/tariffs developed for AA4 better reflect the times of greatest network congestion and are therefore the preferred option for customers to move towards if a customer/retailer is seeking a time of use tariff.
>
> There are three broad options as to how to manage the change of time of use tariff that Western Power offers:
>
> - Replace the tariffs linked to services A3, A4, C3 and C4 with a time of use tariff with more appropriate time periods.
> - It is Western Power's view that this is not possible/desirable under the ETACs in place with retailers as it would represent too large a diversion from pre-existing services being offered which would leave the retailer with the ability to 'reject' the new service and maintain the existing service.

[143] Western Power email 16 August 2018.

- Introduce the new D1 and D2 reference services and leave the existing time of use reference services available to all customers.
- Having two time of use tariffs with very different time periods sends a confusing message to the market about what time periods matter most to the network, reducing the ability to encourage more efficient use of the network.
- Close existing services to new customers, offer D1 and D2 services to customers with AMI.
- This approach means that retailers and customers still have a choice of services/tariffs as there is still the [Anytime Energy (Residential) Exit Service A1, Anytime Energy (Business) Exit Service A2, Anytime Energy (Residential) Bi-directional Service C1 and Anytime Energy (Business) Bi-directional Service C2 available, meaning customers and retailers aren't being 'forced' on to a time of use product, while still signalling the intention to improve the utilisation of the network.

1099. The ERA considers it unlikely that any new user would want to take up the existing time of use services with a 14 hour peak period, as the proposed new service (D1 and D2) has a six hour peak period. Synergy's submission on the draft decision is relevant to this matter:[144]

> Synergy supports [the ERA's view that providing Western Power supplies sufficient metering data to enable a retailer to bill a customer based on its desired time periods, there should be no need for Western Power to offer network reference services to match every time period a retailer may use for retail tariffs] provided the ERA ensures the time bands and price signals proposed by Western Power are reflective of the actual congestion on the network and Western Power is required to substantiate this. The 14 hour peak imposed for the A3 and A4 services since AA1 is an example of where this has not occurred thus denying retailers the opportunity to be innovative in the retail prices and services they offer to their customers.

1100. The approach Western Power proposes adopting for the current residential and business time of use services (A3, A4, C3 and C4) is different from the approach taken for the high voltage and low voltage metered demand services (A5-A6).

1101. As discussed in paragraphs 1086 to 1088 above, Western Power has amended the peak period in the current high voltage and low voltage metered demand services to be consistent with the peak period in its proposed new services. This has resulted in the peak period for existing users shortening from 14 hours to six hours without the users being required to pay for new meters.

1102. In contrast, Western Power proposes retaining the 14-hour peak period for existing residential and business time of use services. As set out above, Western Power submits it is "not possible/undesirable under the ETACs in place with retailers as it would represent too large a diversion from pre-existing services being offered which would leave the retailer with the ability to 'reject' the new service and maintain the existing service."

1103. The ERA considers it very unlikely that retailers would reject a change in the peak period that reduced it from 14 hours to six hours. Synergy's submission on the draft decision requests that the A3 and A4 time periods be amended to include a shoulder period:

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144 Synergy submission on draft decision, June 2018, p. 11.

> Uptake of time of use is unlikely to increase unless the 14 hour peak period charging window in the A3 and A4 service is addressed.[145]
>
> …
>
> Synergy as the largest user will progressively not use the reference services (A3, A4) with a 14 hour peak.

1104. Synergy submits an additional 7am-3pm shoulder period should be added to the A3-A4 services and provides network usage data and customer surveys to support its proposal.

1105. It appears from Western Power's proposal that the new time of use service is only available for properties with advanced meters installed. Synergy's submission on the draft decision raises this matter and refers to a similar situation that arose in the past.

> WP has limited retailer use of the D1-D4 reference services on the basis of an "AMI Meter" …
>
> This is similar to the approach WP adopted in the current A3 reference service .. by using an undefined term "Smartpower meter" as a reference service eligibility criterion. This ambiguous definition resulted in Synergy not being able to install an interval meter to obtain interval data for residential customers via the A3 reference service over the life of AA3.

1106. The ERA considers existing users, particularly those who are already on time of use services with interval capable meters should be able to access the new reference service without being required to pay for an advanced meter.

1107. Furthermore, as Western Power has now amended what it considers to be the peak period, it should not be charging users peak prices for periods it now considers are not peak periods. Consequently, the periods in the existing time of use reference services must be amended to be consistent with the new time of use services.

1108. The ERA also considers the material provided by Synergy supports its position that the 7am – 3pm period should be classified as a shoulder period in the A3/A4 and C3/C4 services.

Required Amendment 14

The new time of use services must be available to users with existing interval capable meters.

Western Power must amend the peak period for the existing residential and business time of use services (A3, A4, C3 and C4) to be consistent with the peak and shoulder periods used in its proposed new residential and business time of use services (D1 and D2) and 7am-3pm should be classified as a shoulder period.

[145] Synergy submission on draft decision, June 2018, p. 25.

Metering services

1109. A common theme from stakeholder submissions on Western Power's initial proposal was the importance of metering services. As discussed in the previous sections, Western Power's proposed new reference services were underpinned by its plans to install advanced meters in all new properties. Synergy's submission highlighted the importance of interval metering data to enable customers to understand the financial effect before changing retail tariffs.

1110. Western Power bundles metering services with each of its reference services.

1111. Metering is dealt with in both the Access Code and the *Electricity Industry (Metering) Code 2012* (Metering Code).

1112. Section 5.28 of the Access Code requires that supplementary matters, which include metering, must be dealt with in the access arrangement in accordance with other relevant regulatory requirements including written laws, the Wholesale Electricity Market Rules and the Technical Rules. In the case of metering, the Metering Code is relevant.

1113. Clause 6.6(1) of the Metering Code is of particular relevance as it sets out requirements for a model service level agreement which includes details of services to be provided and how they can be charged for:

> **6.6 Requirements for model service level agreement**
>
> (1) A model service level agreement must at least:
>
> (a) specify the metering services that the network operator:
>
> (i) must provide (which must include at least all of the metering services that this Code, the Code of Conduct and the Customer Transfer Code require the network operator to provide); and
>
> (ii) may provide,
>
> to other Code participants on request,
>
> and
>
> (b) for each metering service referred to in clause 6.6(1)(a), specify:
>
> (i) a detailed description of the metering service; and
>
> (ii) a timeframe, and where appropriate other service levels, for the performance of the metering service,
>
> and
>
> (c) subject to clause 5.21(9)[146], specify the maximum charges that the network operator may impose for each metering service referred to in clause 6.6(1)(a); and
>
> (d) if any of the charges specified under clause 6.6(1)(c) is variable, provide details of the methodology and cost components that will be used to calculate the variable charge including (where applicable) hourly labour rates, distance-related costs and equipment usage costs; and

[146] Section 5.21(9) states any written service level agreement entered into for testing and/or auditing meters and metering data must include a provision that no charge is to be imposed if the test or audit reveals a non-compliance with this Access Code.

(e) provide that the charges which may be imposed under a service level agreement may not exceed the costs that would be incurred by a network operator acting in good faith an in accordance with good electricity industry practice, seeking to achieve the lowest sustainable costs of providing the relevant metering service

1114. Western Power's current model service level agreement, which was approved in March 2006, specifies "standard metering services" and "extended metering services":

- Standard metering services include scheduled meter readings, standard meter maintenance and the provision of meters for new users.
- Extended metering services are services that arise in a non-routine manner and not necessarily required at every site each year. For example, non-scheduled meter reads and disconnection/reconnection of properties.

1115. The description of each of the current and proposed new reference services, as set out in Appendix E to the access arrangement, states that it includes a standard metering service.

1116. Subsequent to lodging its access arrangement proposal, Western Power submitted proposed amendments to the model service level agreement.[147] Western Power considered its proposed introduction of advanced meters would change and extend the types of metering services available. For example, it would be possible to undertake remote meter readings and remote connections and disconnections rather than the current manual processes. Consequently, Western Power proposed amending the metering services offered under the model service level agreement and changing the classification of some services from "standard metering service" to "extended metering service".

1117. As the ERA will not be making a determination on the model service level agreement until after the access arrangement decision, for the purposes of the draft decision the ERA assumed the model service level agreement had not changed from the current approved version.

1118. The ERA considered the current specification of the metering service for each reference service as a "standard metering service" did not provide sufficient detail of the service provided, for example the frequency and type of meter reading. Neither the current or proposed model service level agreement provided specific details of the metering service provided for each network reference service.

1119. The ERA also considered that bundling the metering service with the reference service limited the ability for users to specify a different metering service, for example, higher frequency readings or interval metered data.

1120. The Australian Energy Council submitted that metering services must reflect the requirements of retailers and end users and not just the monopoly service provider. It noted Western Power's proposed amendments to the model service level agreement would result in remote interval data not being provided more frequently than monthly and that, currently, no service exists to provide manual interval data for residential properties from existing legacy meters.

[147] Western Power, *Submission of Proposed Metering Model Service Level Agreement*, 13 October 2017.

1121. Synergy submitted that it would like to obtain a greater variety of metering services as reference services, in particular, interval data on a regular basis at a reasonable cost. Synergy considers interval meter data is a service many of its customers require. It noted the ability to track and limit their energy use, and to receive notifications and updates, is particularly appealing to customers in hardship and/or on a payment plan.

1122. Synergy submitted that Western Power's AA4 proposal does not support the manual collection of interval energy data as an interim Advanced Metering Infrastructure (AMI) transitional arrangement:

> Consequently the only means of obtaining interval energy data from a deemed Type 6 meter (of which there are between 200-300,000 such meters) is to negotiate yet another non-reference service or replace the meter with a new Type 4 meter. The effect of replacing the meter is to increase the size of WP's asset base for which it will receive a rate of return. However, until the remote communications infrastructure is installed and operational WP will still not provide interval energy data notwithstanding a Type 4 meter is installed.

1123. However, Western Power considered ongoing manual collection of interval data is not in line with good industry practice and would be at a significant cost to end consumers. It submitted:

> The primary difference between the manual collection of accumulation data and interval data is handling time. Accumulation data is collected via a visual reading of a meter's display, while an interval meter requires connection of a device to the meter to download data. Western Power collects more than 6 million meter readings per year. Western Power's decades of experience in both of these methods has been that download times far exceed the handling times for visual reading. Western Power's experience is that the cost of manually collecting interval data is approximately 6 times that of accumulation data. This is consistent with the experience of other utilities within Australia and is reflected in the opex rates approved by the Australian Energy Regulator (AER) in other jurisdictions.
>
> Western Power's position is that where a User requires data sets from a meter that exceed the requirements of the Code and/or requirements relating to operation and settlement of the electricity market that this should be provided on a User pays basis, with cost reflective fees. This is consistent with the Code.
>
> Further, Western Power considers it is in the interest of customers that potential benefits to customers resulting from the ability to better understand how their behaviour impacts their bill be considered in conjunction with the incremental increase in their bill associated with a higher data collection cost. Western Power considers that the use of remote collection technology significantly improves the case for customer benefits associated with interval data. Not only does it provide a data solution, rather than increase the cost of data collection, it reduces this cost.
>
> Western Power's position is that the case for remote data collection and against manual interval data collection is compelling and that the Access Arrangement should seek to avoid a metering services framework that in any way incentivises the manual collection of interval data.

1124. As discussed further below, Synergy requested a manual interval meter service as part of its reference services request.

1125. Section 5.2(c) of the Access Code states that reference services are required, to the extent reasonably practicable, to be specified in such a manner that a user or applicant is able to acquire by way of one or more reference services only those elements of a covered service that the user or applicant wishes to acquire.

1126. Section 5.2(b) of the Access Code states that a reference service should be specified for each covered service that is likely to be sought by either or both of a significant number of users or a substantial proportion of the market for services in the covered network.

1127. The ERA considered these requirements were not being met for metering because:

- The current specification of reference services lacks clarity and detail of the metering service included.
- Bundling metering with the reference service restricts the choice for users who may want a different level of metering.
- The current metering services included with reference services do not meet the requirements of users.

1128. The ERA considered that metering should be supplied as separate reference services with sufficient detail specified so that users can be certain of the service they will receive.

1129. Sufficient services should be specified so that users can select the one that meets their need for each reference service. The ERA considered this would include as a minimum:

- An accumulation meter manual read every two months
- An interval meter manual read with data provided every two months
- An interval meter manual read with data provided every month
- A one-off interval meter manual read
- An interval meter remote read.

1130. The ERA agreed with Western Power's view that metering costs should be recovered on a user-pays basis and based on the cost of the service. Retailers are best placed to determine the value of interval data and decide whether such information is necessary for retail tariff development.

1131. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 revised proposal

1132. Western Power has not accepted draft decision required amendment 14.

1133. Western Power states it agrees with the ERA's desired outcomes which it describes as ensuring clarity and detail on what standard meter services are provided and choice to users who seek a different level of metering. However, it raises concerns about how this can be done:[148]

[148] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 141-145.

> 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.
>
> 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.

1134. Western Power proposes instead 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.
>
> 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]
>
> 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.
>
> 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.
>
> 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.
>
> 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.

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.

Submissions on draft decision

1135. Submissions supporting the draft decision requirement to unbundle metering services were received from ATCO, the Australian Energy Council, the Public Utilities Office, Perth Energy, Synergy and Vector.

1136. ATCO submitted that it:[149]

> … supports the ERA's draft decision that Western Power is to unbundle its metering services into separate reference services. Unbundling advanced metering infrastructure and communications services is a critical first step in the direction of greater competition in metering and energy information services. This is a growing market niche for a diverse range of commercial providers, including technology companies and "behind the meter" specialists, who have the expertise, experience, and financial backing to deliver innovative products and services, such as micro-grids and stand-alone power systems. Ultimately this will deliver benefits and value for energy consumers by stimulating the development and rollout of innovative metering and energy information products and services."

1137. The AEC submits it:[150]

> … would have preferred NEM's power of choice competitive metering but commends the decision to unbundle metering services from transport services to provide greater visibility and transparency of SWIS metering costs than what currently exists today and that this will enable real comparisons to be drawn between the relative efficiency of WEM and NEM meter service provision.

1138. The AEC also considers the ERA should also specify the minimum frequency of interval meter remote reads for example, daily remote interval meter readings.

1139. The PUO submits:[151]

> … as a result of the proposed carve out of metering services from reference services, there is the potential for the development of bespoke non-reference metering services for new and innovative products and services.

1140. Perth Energy submits:[152]

> … notes and supports the move to separately identify the cost of metering rather than rolling it into the reference supply charge. This is economically efficient …

1141. Synergy supports unbundling metering services:[153]

> The inability of retailers to access consumption data at a reasonable cost and frequency has, in Synergy's view contributed to why there has been little innovation in

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149 ATCO Australia Submission Attachment 1, 14 June 2018, p. 7.

150 Australian Energy Council, p. 6.

151 Public Utilities Office, p. 3.

152 Perth Energy p. 9.

153 Synergy submission on draft decision, June 2018, p. 9.

relation to reference services, opportunities to influence customers' use of energy and choice in retail pricing structures.

Therefore, Synergy welcomes and supports the ERA's determination to provide retailers with metering data and reference services to promote competition and give retailers the opportunity to be innovative in the prices and services they offer customers. Synergy considers this is an important paradigm shift for the SWIS and will assist retailers to address a range of customer needs including affordability and adoption of new technologies.

1142. Synergy also submits that Western Power should provide remote interval meter readings on a daily basis.

1143. Vector submits:[154]

In our experience, a competitive regulatory framework for metering services provides choice and better outcomes for consumers and other network users. We understand that the Authority does not have the power to effect a competitive metering framework under the Access Code.

… we commend the Authority in relation to those aspects of its draft decision that promote user choice and price transparency, which we noted to be lacking in the SWIS in our submission on the Authority's Issues Paper on AA4.

For example, the decision to unbundle metering services from bundled reference services into separate reference services will increase price transparency and reduce cross subsidisation.

Considerations of the ERA

1144. As stated in Western Power's revised proposal, it agrees in principle with the ERA's required amendment but considers there are difficulties in implementing it. The ERA acknowledges there are implementation problems that will need to be resolved and that costs need to be minimised. However, for the reasons outlined in the draft decision, the ERA considers metering services should be unbundled.

1145. Western Power describes the legislative metering framework as follows:

Legislative metering framework

As identified by the ERA in its draft decision, metering is a supplementary matter under the Access Code (see section 5.27(c)). 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.

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.

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)

[154] Vector, pp. 1-2.

- 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).

> 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.

1146. Western Power provides examples of what it considers to be inconsistencies between the two frameworks:

> 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 interval meter read for such a meter would clearly be inconsistent with, and not facilitate, the Metering Code.

1147. The metering regulatory framework does not take precedence over the Access Code. The metering and access regulatory frameworks were both put in place under the *Electricity Industry Act 2004* and are designed to work together.

1148. It is clear from clause 5.1(3) of the Metering Code that the clause is not intended to limit the Access Code and that in the event of inconsistency the Access Code prevails.

> Clause 5.1(3) – This clause 5.1 does not limit the Access Code, and, in the event of any conflict or inconsistency between this clause 5.1 and a provision of the Access Code, the latter is to prevail.

1149. Covered services can include metering services that are subject to the Metering Code if they are provided by means of the covered network. Where, however, a supplementary matter such as metering is dealt with under a Code or law, the access arrangement must deal with this matter in a way which is "consistent with and facilitates the treatment" of that matter under the Code or law.

1150. Specifying a limited number of metering services as reference services does not prevent Western Power from offering additional metering services under clauses 5.1(1) and (2) of the Metering Code.

1151. To avoid inconsistency with clause 3.2(2) of the Metering Code, an exception can be provided where Western Power may install a meter with interval energy storage capacity and other enhanced technology features but declare it to be an interval capable meter as an accumulation meter.

1152. The ERA considers specifying a limited number of metering services that are likely to be sought by a significant number of users or substantial proportion of the market can be done in a manner that is consistent with both the network access and metering regulatory frameworks.

1153. Western Power considers there are contractual issues:

> **Contractual considerations**
>
> 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'.
>
> 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.
>
> 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.
>
> 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.
>
> 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.

1154. The standard access contract refers to "Covered Services", it does not limit this to any particular type of covered service. The Applications and Queuing Policy refers to "Reference Services" and does not limit this to any particular type of reference service. If necessary, an amendment could be made to the Transfer and Relocation policy to clarify that a bare transfer can only be made if both the network and metering service are transferred unchanged together.

1155. Western Power considers the Metering Code framework provides users with adequate choice of metering services.

> … 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 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.
>
> 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.
>
> 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.
>
> 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.
>
> 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.

1156. The ERA agrees the model service level agreement can and should provide choice of metering services for users. However, including the most commonly sought metering services which the ERA is satisfied are likely to be sought by a significant number of users and applicants as specific reference services under the access arrangement, results in users being able to more easily obtain the metering services they require and greater transparency in costs. In this regard, the ERA considers that including the bundled "standard metering service" as a reference service does not meet the requirement in section 5.2(c) of the Access Code that, to the extent reasonably practicable, reference services must be specified in such a manner that a user or applicant is able to acquire only those elements of a covered service that the user or applicant wishes to acquire.

1157. Western Power cites various implementation costs

> **Implementation costs**
>
> 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.
>
> 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.

> 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.

1158. The ERA agrees it is important to minimise the administrative costs resulting from any new or amended services.

1159. Western Power argues that its current billing arrangements only support a single charge at each connection point which it considers limits it to only being able to allocate a single reference service to each user.

1160. As Western Power notes in its submission, it charges users for extended metering services. There may be opportunities to utilise and streamline the extended metering service billing arrangements.

1161. Alternatively, as the current network reference service tariff structure includes a separate metering charge it may be possible to use this for the relevant metering service charge.

1162. The ERA considers these issues can be resolved in the further final decision.

1163. For the reasons outlined above, the ERA maintains draft decision required amendment 14.

Required Amendment 15

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. As a minimum this should include:

- An accumulation meter manual read every two months
- An interval meter manual read with data provided every two months
- An interval meter manual read with data provided every month
- A one-off interval meter manual read
- An interval meter read remote read daily

Reference services proposed by users

1164. As discussed above, stakeholder submissions on Western Power's initial proposal indicated that new or different reference services are required by users.

1165. Perth Energy suggested a service for a "thin connection" should be offered:

> … the current tariff structure is not overly flexible and Western Power's AA4 submission should consider tariff structures like 'thin connection'. Given the prevailing growth in behind the meter energy solutions, it is likely that some parts of the SWIS or even individual customer connections would benefit from a 'thin connection' type tariff arrangement over the AA4 period. A 'thin connection' type tariff would be suitable for customers that will be predominantly sourcing their energy behind the meter and will only utilise the transmission and distribution networks as 'contingencies' or intermittently.

1166. The ERA agreed that such a service may be required. However, evidence that this is a service likely to be sought by a significant number of users or a substantial proportion of the market for services was lacking and would be needed for the ERA to require Western Power to offer the service as a reference service. If sufficient information was presented to demonstrate the service is likely to be sought by a significant number of users or a substantial proportion of the market, the ERA would give consideration to it being included as a reference service.

1167. As discussed above, Synergy considered Western Power had not acted consistent with its obligations[155] and requested the ERA to require each of the reference services it had listed in its submission to be included in the approved access arrangement for AA4. It had proposed 25 reference services comprising amendments to Western Power's existing and proposed reference services and entirely new reference services.

1168. Synergy's requested services included details of the pricing structures it considered should apply. Synergy, as a user, can specify the types of services it requires. However, tariff structure and prices is a matter to be considered for reference tariffs, not the specification of reference services.

1169. Synergy's proposed amended and new reference services were categorised as follows:

- Adding requirements to existing reference services to provide interval data, remote connection/disconnection, bi-directional services and the installation of a Type 4 meter where Western Power has not been able to obtain a meter reading for a period of nine months or where a residential customer experiences financial hardship.
- Different time periods for time of use and demand tariffs.
- Distributed generation reference services.
- Reference services that allow capacity and contracted maximum demand to be swapped with other users.
- Direct load control and load limitation services.
- Connection and disconnection services.

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[155] Synergy stated this as being: use all reasonable endeavours to accommodate a user's requirement to obtain covered services (section 2.7 of the Access Code); allow a user to acquire, to the extent reasonably practicable, only those parts of a service it wishes to acquire (section 2.8 of the Access Code); and have an access arrangement that specifies as reference services, those services that are "likely to be sought" by a significant number of users and applicants or a substantial portion of the market, and which (to the extent reasonably practicable) specifies reference services in such a way that a user or applicant is able to acquire only those parts of a covered service they wish to be provided with (section 5.2 of the Access Code).

1170. Each of these is discussed below.

Additional requirements for existing services

1171. Synergy's proposed amendments to existing reference services were mainly connected with metering services. As discussed above, in the draft decision the ERA considered the existing metering services needed to be specified clearly and should be included as separate reference services. In addition, Western Power should include a service for providing interval metering data.

1172. As requested by Synergy, retailers should also have the ability to choose (and pay for) a meter with remote reading functions if required.

Different time periods

1173. Synergy requested different time periods from those offered by Western Power in its various time of use services.

1174. As discussed above, Western Power should base its reference services on the requirements of its network users. However, the ERA considered Western Power is best placed to identify the periods of network congestion and structure its network services around this.

1175. Retailers are likely to use different time periods from the network operator as they have broader factors to consider than just the network. Providing Western Power supplies sufficient metering data to enable a retailer to bill a customer based on its desired time periods, there should be no need for Western Power to offer network reference services to match every time period a retailer may use for retail tariffs.

1176. Offering metering services as a separate reference service should facilitate provision of this data to retailers.

Distributed generation reference services

1177. Synergy referred to sections 7.9 and 7.10 of the Access Code regarding prudent discounts and discounts for distributed generating plant. The prudent discount provisions allow the service provider to discriminate between users in its pricing of services to the extent it is necessary to do to aid economic efficiency. Pricing for distributed generation must include a share of any reductions in either or both of the service provider's capital and operating expenditure arising as a result of the entry point for the plant being located in a particular part of the network:

> WP's prudent discount scheme does not provide sufficient ability for a network user to use private assets and investments to receive a prudent discount. The current arrangement requires a user and WP to negotiate a discount. However, the arrangement provides no framework or certainty to deliver private investment to reduce network costs and improve network efficiency other than through a requirement to negotiate. The absence of a workable prudent discount mechanism has resulted in users not being able to obtain and use the discount to financially incentivise their customers to invest in behind the meter solutions such as energy storage, EVs, solar PV, and home energy management services delivered through digital applications.

1178. Synergy stated it was unaware of any situations where Western Power provided discounts for the circumstances above. It considered this should be questioned by the ERA given the increasingly constrained Western Power Network and the extent to which distributed generation connections have increased in recent years.

1179. Synergy sought:

- a distributed generation low voltage connection service – residential
- a distributed generation low voltage connection service – business
- a distributed generation high voltage connection service – business

1180. Western Power must meet the requirements of the Access Code regarding prudent discounts and pricing for distributed generation. However, the ERA considered these would be negotiated between a service provider and user, rather than being part of a reference service.

1181. The circumstances of each connection would need to be considered to establish whether there was justification to allow Western Power to discriminate between users to aid economic efficiency or, in the case of distributed generation, the level of reductions in either or both of Western Power's capital and operating expenditure arising as a result of the entry point for the plant being located in a particular part of the network.

Capacity and contracted maximum demand swaps

1182. Synergy sought reference services to allow it to swap capacity and contract maximum demand with other users. It considered these services were required to allow it to share:

- Generation connections between users with different network access contracts for example, co-located wind and solar facilities sharing the same connection point.
- Load connections between users with different network access contracts to allow consumers to be supplied electricity by two separate suppliers.

1183. Transfers between users are dealt with in the transfer and relocation policy and applications and queuing policy. It is likely the specific details of any such transfers will be particular to each case and it would be difficult to specify a standard service.

1184. In the draft decision, the ERA considered there was not sufficient evidence to demonstrate this is a standard service likely to be sought by a significant number of users or a substantial proportion of the market.

Direct load control and load limitation services

1185. A direct load control service turns power to a load or appliance on or off remotely, thus controlling the quantity of power that a load can consume, resulting in a reduction to the quantity of power that a load can consume through the network.

1186. A load limitation service reduces the power transfer capability or demand at a connection point resulting in a reduction to the quantity of power that a load can consume through the network.

1187. These services require remote communication with advanced meters. A meter with remote communications would need to be installed by Western Power and paid for by the user requesting the service. In the draft decision the ERA noted that if Synergy was able to demonstrate that this is a service sought by a significant number of users or a substantial proportion of the market, then Western Power should offer it as a reference service.

Connection and disconnection services

1188. Synergy sought services for remote disconnection/reconnection and manual disconnection/reconnection. It considered reconnection or disconnection a covered service and could be part of (or could also be stand-alone) a reference service or a stand-alone reference service.

1189. Connection and disconnection services are currently provided as extended metering services and, therefore, are not included in the existing network reference services. The terms and prices are set out in the model service level agreement.

1190. The ERA agreed it would provide greater clarity to users if the manual connection/disconnection process was included as a reference service in the access arrangement.

Western Power's revised proposal

1191. Western Power has not added any reference services and does not appear to have given any further consideration to the reference services sought by users. It submits:[156]

> The ERA states Western Power should base its reference services on users' requirements, rather than on what Western Power thinks is required. 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.

Submissions on the draft decision

1192. Submissions on the draft decision from AEC, Perth Energy, Synergy and WALGA all consider the access arrangement does not specify a reference service for each covered service that is likely to be sought.

1193. The Australian Energy Council:[157]

> … considers the ERA has in its Draft Decision:
>
> (a) Addressed member concerns in relation to mandating time of use reference services, except that the ERA has not clarified whether, and if so how, differential pricing will apply to the different time of use bands.
>
> (b) Acknowledged network users do not consider the network operator has considered network user requirements in its development of reference services. However, the ERA has not directly addressed the question of the extent to which the network operator modified or introduced new reference services directly in response to demand from network users.
>
> (c) Did not benchmark the network operator's range of reference services against network services offered by distribution network service providers or transmission network service providers in the NEM or elsewhere to determine whether the network operator's proposed reference services represent "best practice", or whether it is unnecessarily narrow in meeting the needs of network users.
>
> The Energy Council understands from the Draft Decision and its member's feedback that network users have made requests to the network operator in respect of the

156 Western Power revised proposal p. 143.

157 Australian Energy Council, pp. 3-5.

network services required as reference services. However, none of these requests were reflected in the network operator's proposed revisions to the references services in the Access Arrangement.

Consequently, the Energy Council submits the ERA’s required amendments in the Draft Decision do not result in an access arrangement that is consistent with section 5.2 of the Access Code because it does not specify a reference service for each covered service that is likely to be sought by either or both of a significant number of network users and applicants or a substantial proportion of the market for services in the covered network.

The network operator's response to addressing peak demand at the "small customer" level has focused on an approach to time of use pricing that penalises end-use customers if they consume in peak periods, thus incentivising customers to consume off-peak. Importantly, this traditional approach is predicated on retailers selecting time of use network services to underpin time of use retail products that respond to the needs of retail customers who are free to select time of use or any-time energy tariffs. As such, time of use network and retail tariffs in the south west interconnected system (SWIS) have been "voluntary".

The Energy Council acknowledges the voluntary nature of time of use tariffs means that many, if not most, end use customers that select time of use products are likely to fall into one of two classes:

- end use customers whose current load profile means they will be better off on time of use products; or

- end use customers who consider they will be able to modify their current load profile under a time of use product, resulting in them being better of in future.

The Energy Council acknowledges that this "self-selection" bias means a large number of end use customers whose behaviour disproportionately contributes to coincident peak demand may not be confronted with the full economic cost of their load profile.

Nevertheless, the network operator's proposal to mandate time of use network tariffs based on meter type is plainly inconsistent with the Access Code and the ERA correctly required that the proposal be deleted from the network operator's proposal.

In the Energy Council's view, the network operator has a number of non-network options available to it to avoid capital expenditure associated with serving peak demand that are also likely to be consistent with the requirements of the Access Code.

Embedded generation, micro-grids, standalone power systems, demand management programs, and battery systems etc (non-network solutions) all have a vital role in promoting the efficient utilisation of network and avoiding capital expenditure. These however, are not monopoly assets or services but are properly assets and services that can be provided via competitive markets in response to efficient network signals. The Energy Council’s view is that non-network solutions must be promoted and supported by network services, not restricted or limited by them.

The Energy Council seeks to draw specific attention to the network operator’s prudent discount mechanism in that regard. The Energy Council considers the existing prudent discount scheme does not address the need in the SWIS for the network operator’s reference services to support network users offering non-network solutions to end use customers to reduce their electricity costs or consume electricity more efficiently. The Energy Council's members are seeking to offer non-network solutions to end use customers to reduce their electricity costs or consume electricity more efficiently. Such an outcome is consistent with the Access Code.

Conceptually, the network operator's prudent discount contemplated by the Access Code could be used to reward a particular network user for engaging in conduct that avoids network investment by means of a discount and share the cost of that discount proportionately across all other network users.

The Energy Council’s Western Australian members advise they are not aware of examples of the network operator offering a prudent discount under the scheme. The

> prudent discount scheme is also highly dependent on a network user demonstrating the case for a discount in circumstances where a network user is at a relative disadvantage in all matters relating to the management, planning and operation of the network and the network operator is not necessarily financially incentivised to agree to offer a prudent discount for non-network solutions when it would result in the network operator not making a capital investment in the network on which it would earn a regulated return, subject to that investment meeting the new facilities investment test.
>
> The Energy Council notes the significant concern in the NEM at the prospect of distribution network businesses potentially using, or seeking to use, their market power to limit competition in non-network solutions and to earn regulated returns on contestable energy market services.
>
> These concerns prompted the Australian Energy Regulator's ring-fencing guidelines, which were initiated in July 2017.
>
> The Energy Council submits any requirement for a network user to negotiate with a network operator to obtain a network service that incentivises a customer to use alternative non-network solutions will be of limited use because of the inherently unequal bargaining power between a monopoly network owner and contestable service provider. Further, it is far from clear that the network operator is financially incentivised to offer such a network service if the network operator could, instead, capture the benefit of behind the non-network solutions by utilising its regulated assets.
>
> Plainly, a regulated reference service would avoid the aforementioned conflicts of interest and could facilitate non-network solutions to improve network efficiency and would be available to any network user. It would also, in the Energy Council's view, be consistent with the Access Code objective of promoting the economically efficient investment in and operation of and use of networks and services of networks in Western Australia to promote competition in markets upstream and downstream of the networks.
>
> Accordingly, the Energy Council requests the ERA to determine a reference service or services that meets the Access Code's competition objective in terms of network users being able to provide non-network solutions to customers on the basis that such a reference service is likely to be sought by either or both of a significant number of users and applicants or a substantial proportion of the market for services in the covered network.

1194. Perth Energy reiterated its view expressed in its submission on Western Power's initial proposal that Western Power should offer a "thin" connection as a reference tariff. Perth Energy refers to the ERA's statement in its draft decision that evidence that this is a service likely to be sought by a significant number of users is currently lacking and would be needed for the ERA to require Western Power to offer the service as a reference service. Perth Energy submits:

> … there are already some 230,000 customers who have installed solar systems and could be considered as potential users of such a tariff over the term of AA4. We say this because of several driving factors:
>
> - The price of batteries is reducing and already they are being perceived as another "standard" item for homes in the same way that air-conditioning became "standard" and solar PV is becoming "standard";
> - The system instability issues caused by high solar usage, and high solar export to the grid, that AEMO have publicly highlighted are likely to lead to financial or regulatory incentives for the installation of batteries behind the meter; and
> - Retailers are actively considering the development of "virtual power plants" which will drive further investment in behind the meter storage.
>
> On a broader view, Government is currently encouraging an increase in housing density in locations that are close to public transport facilities. It is noticeable, even in relatively recent suburbs, that houses are being demolished and replaced by two or

> three units on the same site. If these new dwellings, or other existing dwellings, have access to a “thin” connection then they defer or potentially eliminate the need to strengthen the distribution system which would otherwise be required. This cost saving should be identified by Western Power and credited as part of the “thin” tariff structure in accordance with the “causer pays” principle.

1195. Synergy submits that it was encouraged by various statements made by the ERA in its draft decision about the need for Western Power to provide reference services that reflect requirements of users and the ERA’s recognition that many users did not consider their reference service needs were met. However, Synergy is concerned the ERA has largely not addressed its requests for reference services.

> As a result, Synergy strongly asserts WP’s proposed AA4 largely does not reflect any of the services proposed by users (including Synergy), is not based on user requirements (in accordance with section 5.2 of the Access Code), nor does it meet the Access Code objective of promoting competition upstream and downstream of the network.
>
> Synergy considers the ERA has erred in its conclusion of Synergy’s references services request as:
>
> “Synergy’s proposed amendments to existing reference services are mainly for metering services”
>
> [ERADD 735]. Synergy considers this conclusion may have inadvertently caused the ERA to not fully consider Synergy’s request for conveyance services consistent with section 5.2 of the Access Code.
>
> The inability of retailers to access consumption data at a reasonable cost and frequency has, in Synergy's view, contributed to why there has been little innovation in relation to reference services, opportunities to influence customers’ use of energy and choice in retail pricing structures.
>
> Therefore, Synergy welcomes and supports the ERA’s determination to provide retailers with metering data and reference services to promote competition and give retailers the opportunity to be innovative in the prices and services they offer to customers. Synergy considers this is an important paradigm shift for the SWIS and will assist retailers to address a range of customer needs including affordability and adoption of new technologies.
>
> However, the ERA did not approve the majority of Synergy’s reference services. It is important to recognise that retailers require both energy data and references services based on users’ requirements to enable the competition and innovation contemplated by the ERA [ERADD 675]. In addition, Synergy considers this type of competition and innovation can, and should, occur right now for customers and does not have to wait until further deregulation of the market for customers to realise the benefits of flexible and innovative reference services. Nevertheless, section 5.2 of the Access Code does not require further deregulation of the market to approve reference services based on users’ requirements.
>
> Synergy notes there is a general recognition by users’ of the benefits advanced metering infrastructure (AMI) can provide [ERADD 364]. However, Synergy considers it is also important to recognise the benefit provided by AMI can only be realised or delivered if:
>
> 1. retailers have adequate reference services to develop the retail offerings and value propositions for customers; and
>
> 2. retailers and customers are provided with adequate metering data to support the take up of the retail offerings and value propositions; and
>
> 3. customers see the benefit and value proposition.
>
> It is important to recognise reference tariffs represent a substantial portion of the cost of a customer’s electricity bill. This cost cannot be addressed by solely providing more

> interval energy data but it also requires reference services that provide opportunity for innovation in the prices and services offered to customers.
>
> Synergy considers flexible reference services drive innovative retail offerings, which in turn drives the need for AMI and metering data. This approach, in Synergy's view, is the major driver for a successful AMI deployment – as opposed to mandating or a roll-out based solely on new and replacement installations. Therefore, Synergy considers the value of adequate and flexible reference services for the successful implementation of AMI should not be underestimated, otherwise Western Australian customers face the risk of the same AMI experience as Victorian customers.

1196. Synergy has identified five new residential and business reference services and amendments to two existing reference services which it considers are the minimum necessary for Western Power's access arrangement to meet the requirements of section 5.2 of the Access Code.[158]

1197. WALGA's submission proposes the following changes to reference services:

- A clearer basis of services, more robustly defining the street lighting services that Western Power provides including agreement on technology.
- Provision within the coming regulatory period to adopt a new metering type based on metering-grade information technology within smart street lighting controllers and similar devices.

1198. Western Power is correct in its view that, when approving a proposed access arrangement, the ERA must determine whether the proposed access arrangement meets the Code objective and the requirements set out in Chapter 5. If the ERA considers that the Code objective and the requirements set out in Chapter 5 are satisfied, it must approve the proposed access arrangement. If the Code objective or a requirement set out in Chapter 5 is not satisfied, it must not approve the proposed access arrangement. To avoid doubt, if the ERA considers that the Code objective and the requirements set out in Chapter 5 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 section 4.28 of the Access Code.

1199. However, as discussed in required amendment 14, the access arrangement must specify a reference service for each covered service that is likely to be sought by either or both of a significant number of users/applicants or a substantial proportion of the market for services in the covered network. Accordingly, it is open to the ERA to require additional reference services if it is of the view that such services meet the test in section 5.2(b)(i) or (ii) of the Access Code. That said, the ERA does not consider that every reference service sought by a large user automatically satisfies the test in section 5.2(b)(i) or (ii) of the Access Code .

1200. Section 5.2(b)(i) refers to a significant *number* of *users*. The *significance* of the *number* of users will therefore depend upon the total number of users. In this respect, users are defined in section 1.3 of the Access Code to mean a person who is a party to a contract for services with a service provider. This does not include customers of retailers or consumers unless they are also parties to an access contract.

1201. Similarly, section 5.2(b)(ii) requires a *substantial proportion of the market* for services in the covered network. Both criteria therefore require a consideration of the number

[158] Synergy submission on draft decision, June 2018, p. 3.

of users or proportion of the market (by value and/or volume) relative to the total number of users or total size of the market for services (by value and/or volume). . By way of example, one user may be a significant number if the total number of users is less than 10, however if the total number of users is over 100 it is difficult to see how one user could constitute a *significant number* of *users*.

1202. The submissions on the draft decision from users include details of services that are sought by a significant number of users or a substantial portion of the market that are not currently available as reference services. These are:

- Services that enable network users to provide non-network solutions to customers (as described in the Australian Energy Council's submission).
- A thin connection (as described in Perth Energy's submission).
- Services set out in Synergy's submission:[159]
  - New multi-part time of use residential and business reference services[160]
  - New distributed generation service[161]
  - New capacity allocation service[162]
  - New direct load control and load limitation[163]
  - New supply abolishment and remote connection/disconnection services[164]
- New street lighting services (as set out in WALGA's submission):
  - A clearer basis of services, more robustly defining the street lighting services that Western Power provides including light levels, spillage and technology.
  - An LED replacement service.
  - Different ownership models.
  - A new metering type based on metering-grade information technology within smart street lighting controllers and similar devices.

1203. The services that enable network users to provide non-network solutions to customers described in the Australian Energy Council submission, Perth Energy's "thin connection" and Synergy's distributed generation service are all similar in nature so could be provided by the same reference service.

1204. In the draft decision, the ERA agreed that a thin connection service may be required. However, evidence that this is a service likely to be sought by a significant number of users or a substantial proportion of the market for services was lacking and would be needed for the ERA to require Western Power to offer the service as a reference service.

[159] Synergy also considered that the A1-A4 exit services and C1-C4 bi-directional services should be consolidated, which is discussed in paragraphs x to x above and that the A3 and A4 time of use reference services should be amended to include a shoulder period, which is discussed in paragraphs 1103 to 1108.

[160] Synergy submission on draft decision, June 2018, pp. 11-12.

[161] Synergy submission on draft decision, June 2018, pp. 13-20.

[162] Synergy submission on draft decision, June 2018, pp. 20-22.

[163] Synergy submission on draft decision, June 2018, pp. 22-23.

[164] Synergy submission on draft decision, June 2018, p. 24.

1205. The draft decision also noted the level of reductions in either or both Western Power's capital and operating expenditure, and therefore the tariff that would be charged for the connection, would depend on where the entry point of the distributed generation was located.

1206. Perth Energy's submission on the draft decision notes there are already 230,000 properties with solar systems installed and that this number will increase.

1207. Synergy's submission on the draft decision includes additional information on the multi-part time of use, capacity allocation, direct load control and load limitation and supply abolishment and remote connection/disconnection services it requires. As noted above, Synergy is the only retailer that can supply customers consuming less than 50 MW each year. In the contestable market – customers consuming more than 50 MW each year – there are six major retailers, with Synergy having the largest market share. Consequently, the ERA is satisfied the services proposed by Synergy are likely to be sought by a substantial proportion of the market.

1208. The required new street lighting services were submitted by WALGA on behalf of the local governments that it represents. Local governments are the main users of streetlight services, so the services are required by both a significant number of users and a substantial proportion of the market.

1209. In order to satisfy the requirements of section 5.2(b)(i) and (ii), Western Power must include the reference services listed in paragraph 1202 above or identify how its existing reference services can be utilised to enable users to obtain such services.

Required Amendment 16

Western Power must include reference services that meet the services listed in paragraph 1202 of the final decision or identify how existing reference services can be utilised to enable users to obtain these services.

Other amendments to reference services

1210. Western Power considered the current reference services document (Appendix E to the access arrangement) which sets out all the reference services, including the eligibility criteria, reference tariff, service level and applicable contract for each service, did not include sufficient detail.

1211. Western Power proposed amendments to include definitions for all terms used in the document and updated to incorporate the proposed new reference services and amended reference services. It considered these revisions should:[165]

> … provide clarity around which customers are classified as residential, voluntary/charity or business. In addition, all of the new services and modifications to services discussed above have been incorporated into the document.

[165] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 255.

1212. The draft decision required the Appendix to be amended to reflect the ERA's required amendments set out above.

1213. The ERA identified further minor required amendments to Appendix E, which are set out in the table below.

Table 172 ERA draft decision required amendments to the definitions of reference services set out in Appendix E of Western Power's proposed access arrangement

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.

1214. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision Required Amendment 15

Western Power must amend Appendix E of the access arrangement in line with Table 116 of the draft decision.

1215. In its revised proposal, Western Power states it has accepted the required amendment as proposed and made the necessary changes to Appendix E. However, as noted in its response to required amendment 13, it will no longer provide reference services D3 and D4 so it has not included any amendments to those services.[166]

1216. It has also proposed further amendments:[167]

> 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:

[166] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, Western Power revised proposal, pp. 145-146.

[167] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, Western Power revised proposal pp. 146-147.

- 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).

1217. The changes to metering definitions and conditions (including the new clause 1.4 and Annexure A) will need to be revised to be consistent with the ERA's required amendment 15 to unbundle metering services.

1218. The amendments to A5 to A8 and new reference services C5 to C8 have been addressed above.

1219. The amendments to A3, A4, C3 and C4 have been addressed above.

1220. The amendments to definitions for "non-residential premises" and "Small Use Customer" appear reasonable.

Required Amendment 17

Western Power must revise the changes to metering definitions and conditions (including new clause 1.4 and Annexure A) in Appendix E Reference Services, to be consistent with required amendment 15.

Reference Service Eligibility Criteria

1221. Submissions from the Australian Energy Council and Synergy on the draft decision raise concerns with the reference service eligibility criteria which they consider may result in users not being able to access AA4 reference services

1222. The Australian Energy Council submits:[168]

> The Energy Council's Western Australian members are concerned that Western Power has the ability to deny network users the ongoing right to use some or all reference services during the AA4 period.
>
> Western Power has included the following provision in all AA4 reference services that permits it to deny a network user the right to use any or all reference service in the future based on its opinion of whether the network users ETAC is materially different from the AA4 ETAC approved by the ERA.
>
> > Each of the following does not apply under an agreement with Western Power:
> >
> > The terms and conditions of the *access contract* under which the *service* will be provided are materially different to the Applicable Standard Access Contract for this service.
>
> In addition, it is important to note Western Power has not specified any objective criteria in relation to what constitutes "materially different". It is based solely on Western Power's opinion that the reference service should be denied to a network user. Western Power may exercise this right at any time even if the network user has been previously using the reference services for many years to supply its customers under standard ETACs approved by the ERA in access arrangement periods 1-3. Therefore, Western Power may deny reference services to a user with an AA1 ETAC, approved by the ERA, because it forms the opinion that the AA1 ETAC is materially different to the AA4 ETAC.
>
> Under the Access Code a reference service is a service likely to be sought by a significant number of network users. Further, the ERA also determined retailers should have choice i.e. mandating reference services is not consistent with the Access Code objective and Western Power should base its reference services on network user requirements rather than basing it on what Western Power thinks is required [DD659, 686, 688]. Therefore, Western Power's proposal for it to have the unilateral ability to deny network users the ongoing right to choose and use reference services, based on what Western Power considers is a material difference in ETACs, is inconsistent with these principles.
>
> The Energy Council considers this unilateral ability to deny reference services and the manner it is being implemented, under the reference service eligibility criteria, is not commercially workable.[169] In addition, the Energy Council considers it is also inconsistent with the Code objectives and clause 4.342 of the Access Code.

[168] Australian Energy Council, p. 6 and p. 9.

[169] Noting the ERA's views on what is commercially workable [DD1284].

Therefore, the Energy Council submits on behalf of its members, the ERA consistent with the Access Code should not approve this reference services eligibility criterion that provides Western Power with the right to deny a network user the ongoing right to use reference services.

…

The Energy Council notes that network users [DD1296, 1297] highlighted there are different versions of access contracts in use and the ERA considers each version of the ETAC should represent a commercially workable access contract at the time it is approved. However, the network operator, under its proposed reference service eligibility criteria, does not permit a network user to use any reference service if their access contract is materially different to the standard access contract. (Refer each reference criteria for details.) There is no objective definition of what constitutes "materially different". Therefore, if there is a difference of opinion between the network user and the network operator, the latter can use its monopoly power in negotiating the ETAC with a prospective user.

The Energy Council is concerned the network operator, through the reference service eligibility criteria, unnecessarily restricts a network user's future access to reference services based on the version of ETAC they may [have] with the network operator and whether the network operator considers it to be materially different to the standard access contract approved by the ERA.

The Energy Council contends this unreasonable and commercially unworkable on the basis such a requirement does not promote competition upstream or downstream of the network. Network users who have been using reference services under their negotiated ETAC should be allowed to continue to do so in the future. Therefore, the Energy Council requires the ERA to clarify the intent of this restriction and ensure network users retailers who have been using reference services previously will be allowed to do so under AA4 under a negotiated ETAC.

1223. Synergy's submission raises similar issues:[170]

In its draft decision, the ERA stated it had reviewed information provided by Synergy in support of Synergy's claim it had pre-existing contractual rights it would be prevented from exercising if the ERA approves certain aspects of WP's proposed revisions to its Access Arrangement.

Following that review, the ERA considered there are no pre-existing contractual rights Synergy would be precluded from exercising in a manner that is prohibited by section 4.34 of Access Code.

Synergy does not agree with the ERA's position on this matter. In Synergy's view WP's proposed AA4 will have the effect of depriving Synergy of its pre-existing contractual rights so as to materially impinge Synergy's ability to supply electricity to more than one million residential and business customers by being potentially denied access to existing reference services. This is because Synergy's existing electricity transfer access contracts (Synergy's ETAC) is "materially different" to the standard access contract available under AA4.

…

Synergy is concerned the ERA has not in its draft decision or elsewhere given consideration to Synergy's concern with respect to the reference service eligibility criteria, in circumstances where the standard electricity transfer access contract approved in respect of AA4 (AA4 SETAC) is materially different to access contracts that exist between WP and users.

…

In essence, Synergy's concern is as follows:

[170] Synergy submission on draft decision, June 2018, pp. 30-36.

- It is a characteristic of the "eligibility criteria" for each reference service that users are not eligible for any reference services for AA4 if, among other things, "the terms and conditions of the access contract [between WP and the user] under which the service will be provided are materially different to the applicable standard access contract for the service" (emphasis added).
- This eligibility criterion was introduced by WP in its proposed revisions to its Access Arrangement for the third access arrangement and approved by the ERA in respect of the same period. Synergy raised various concerns in relation to the criterion which were not accepted by the ERA prior to its Final Decision on Proposed Revisions to the Access Arrangement for the WP Network dated 5 September 2012 – see at [132] of that Final Decision.
- The legal meaning of the extracted text from the eligibility criteria quoted above has clearly not been tested by a Court but the term "materially different" would, in Synergy's view, be enlivened by differences that are not immaterial with respect to the services provided under those terms and conditions, performance standards in respect of those services or the risk allocation regime described in access contracts, being in respect of insurance, liability and indemnity.
- Synergy understands that most access contracts in place between WP and users are based on the form of the standard electricity transfer access contract that was approved by the ERA in respect of WP's first Access Arrangement period. That model electricity transfer access contract:
- requires users to continue to meet the eligibility criteria for connection points that receive a reference service (defined as "Reference Service Points" in the AA4 standard access contract); and
- entitles users to select reference services from time to time as those reference services are amended in the Access Arrangement, consistent with the Access Code.
- It is also clear from the term in respect of which legacy ETACs are intended to be effective, as well as the mechanism for the selection of reference services, the contracts are intended by the parties to apply from one Access Arrangement period to another for the purposes of WP supplying, and the user obtaining, the provision of reference services.
- For these reasons, we consider there are two primary rights the approval of AA4 of which will deprive Synergy of prior contractual rights.
- Users will be deprived of their existing contractual right to be provided reference services (including as the A1 reference service) under the terms of their current ETACs from one Access Arrangement period to the next (subject to meeting the eligibility criteria). This arises because, generally, legacy ETACs will be "materially different" to the standard access contract available under AA4. Synergy has previously provided the ERA evidence of the provisions under ETACs which it considers are materially different from the proposed AA4 SETAC. Therefore, the user will not be able to comply with its contractual requirement and will be forced to enter into a new ETAC that is not materially different to the standard access contract to continue to receive reference services (or in fact any services – see arguments further below). This has major implications for retailers who have contracted to supply electricity to customers based on an ETAC that is not the AA4 SETAC.
- Users will be deprived of their current right to select and use reference services from time to time under terms of their current ETACs. In effect, the changes proposed in AA4 will deprive users on legacy ETACs of their existing contractual right to select services (under the equivalent of clause 3.2 of the standard access contract) and have those services provided on the terms of the legacy ETAC.

In Synergy's view, it is clear from the terms of standard access contracts in previous Access Arrangements, and the terms proposed in the AA4 SETAC, that access contracts are designed to continue to have effect from one Access Arrangement period to the next. Generally, this occurs because, on and from the commencement of an Access Arrangement period (e.g. AA4), reference services offered under the previous Access Arrangement (e.g. AA3) will cease and the services provided to users becomes the new reference service. This is supported by the fact there is no mechanism to transfer a service that ceases to be a reference service (e.g. due to the user being unable to comply with the eligibility criteria) to being a non-reference service. Therefore, the proposed changes to AA4 will result in a circumstance where it is unclear how the legacy ETACs continue to apply to all users. For example, when the eligibility criteria is no longer capable of being met:

- Does the user simply breach the equivalent of clause 3.3 of the standard access contract for the remainder of the term?
- Does the service become a non-reference service with no defined service standards?
- Is the user obliged to re-negotiate the terms of the legacy ETAC so that contract is no longer "materially different" to the AA4 SETAC?

The consequence of the foregoing is not only that users will be deprived of their primary rights to continue to receive reference services on the terms of its legacy ETAC but also the party will be deprived of its rights to exercise any secondary right that party may have under the legacy ETAC:

- negotiated or in place because of the ERA's previous decisions in prior Access Arrangement periods;
- that exists prior to the earlier of the submission deadline for the proposed revisions to the Access Arrangement and the date on which the proposed submissions to the Access Arrangement was submitted; and
- that are, in substance, different to clauses contained in the AA4 SETAC.

Approving the reference services eligibility criterion, in Synergy's view, amounts to a breach of section 4.34 of the Access Code because in essence it results in the effect of preventing the exercise of the primary right and any secondary right under the legacy access contract.

Synergy considers this may be remedied by either:

- including a comprehensive definition of "materially different" to ensure any access contract that is based on a standard electricity transfer access contract approved by the ERA is excluded from the effect of the provision; or
- deleting the words “The terms and conditions of the access contract under which the service will be provided are materially different to the Applicable Standard Access Contract for this service,” from each proposed AA4 reference service eligibility criteria; or
- the ERA requesting WP provide it with a copy of each access contract between it and a user in order to ascertain what amendments to the proposed AA4 SETAC may not be made in order to ensure compliance with section 4.34 of the Access Code.

Synergy considers the first option is likely to be preferable and is consistent with the policy rationale adopted by the ERA in its Final Decision in AA3 in approving the subject eligibility criterion.

Considerations of the ERA

1224. Both the Australian Energy Council and Synergy have raised concerns regarding the current eligibility clause for reference services that they consider will result in users not being able to continue to access reference services during AA4. The ERA assumes it is not Western Power’s intention that this would occur.

1225. Synergy proposes various amendments to ensure that it won't be prevented from exercising its primary right to continue to receive reference services on the terms of its legacy access contract and also any secondary rights under the contract. Synergy's preferred amendment is to include a comprehensive definition of "materially different" to ensure any access contract that is based on a standard electricity transfer access contract approved by the ERA is excluded from the effect of the provision.

1226. The ERA agrees a comprehensive definition of "materially different" would provide certainty and preserve ongoing rights to use reference services. Consequently it requires Western Power to amend the eligibility criteria for reference services by adding a definition of "materially different" that provides sufficient clarity and certainty to users with access contracts that they will be able to continue to use reference services during AA4 under their existing contracts.

Required Amendment 18

Western Power must amend the eligibility criteria for reference services by adding a definition of "materially different" that provides sufficient clarity and certainty to users with access contracts that they will be able to continue to use reference services during AA4 under their existing contracts.

Non-reference services

1227. Where a user requests non-standard services, Western Power advised it can develop a customised product as a non-reference service:[171]

> The specifics of the non-standard service and corresponding tariff provided by Western Power is negotiated with the customer following a request for a non-standard service. The non-standard services we provide under non-reference service contracts are not listed or priced, other than in the contract. Further, as these services are customers, they do not have minimum service standards provided.

1228. Western Power provided the following examples of non-reference services:[172]

- processing and administration fees for an application for network access as detailed in the applications and queuing policy
- network access services with conditions that vary from reference services, including:
  - transmission connected users that have agreed to accept an interruptible service to avoid paying the cost prohibitive deep connection costs that would otherwise be required to provide a standard service
  - users with additional network redundancy or back-up supply available where they have paid for increased security and reliability for their connection

[171] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 83.

[172] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 83.

  - connections for which the user's equipment does not meet the Technical Rules, but for which Western Power has sought an exemption from the ERA, and Western Power is required to provide additional services

- all other services that are not core to the transport of electricity from the supplier to the end-use customer, including, for example the elevation of overhead lines to allow the transport of high loads and the provision of pre-payment metering services.

1229. Community Electricity raised concerns that there are no minimum terms and conditions or service standards for non-standard services, and it did not consider Western Power should set prices without oversight:

> While we support the notion of flexibly facilitating access to users, this proposal circumvents the reasonableness mandate that Western Power already ignores. We object to Western Power being authorised to capaciously and arbitrarily impose its monopoly power on a developing market. We consider that it will abuse this power to discriminate between users and erect barriers to entry. The extent to which Western Power bullies applicants into accepting onerous terms and conditions should not be underestimated. We suggest that the reasonableness mandate should be enforced and a low cost appeal mechanism where it is perceived not to do so. The alternative is to motivate disconnection from the grid.

1230. The Access Code does not require a service provider to include in an access arrangement a designation or description of non-reference services or a standard access contract for non-reference services. Under section 4.29(c), the ERA cannot require a service provider to include these matters in an access arrangement.

1231. The ERA has a limited role in managing access requirements between Western Power and users. In this case, the ERA's role is to ensure the access arrangement includes reference services that meet the requirements of the Access Code. This includes ensuring there is a reference service for each covered service that is likely to be sought by a significant number of users.

1232. Under the Access Code the ERA, when notified of an access dispute, may settle the dispute by conciliation or refer the dispute to an arbitrator. It may also refer contractual disputes to the arbitrator. Beyond these statutory requirements, the ERA does not have a role in managing negotiations between the parties for non-reference services.

1233. If a significant number of users seek a particular network access service not currently offered as a reference service then, under section 5.2(b) of the Access Code, consideration would need to be given for such services to be included as reference services.

PRICING METHODS, PRICE LIST AND PRICE LIST INFORMATION

Access Code requirements

1234. Section 5.1(e) of the *Electricity Networks Access Code 2004* (**Access Code**) requires an access arrangement to include pricing methods in accordance with the requirements of chapter 7 of the Access Code.

1235. Section 7.1 of the Access Code defines "pricing methods" to mean the structure of reference tariffs included in an access arrangement, which determines how target revenue is allocated across and within reference services.

1236. Section 7.2 of the Access Code provides that an access arrangement may contain any pricing methods; provided that the pricing methods collectively meet the objectives set out in sections 7.3 and 7.4 and otherwise comply with the chapter 7. A note under section 7.2 gives examples of tariffs that may result from pricing methods, indicating that tariffs or parts of tariffs may be set to take into account matters such as different classes of users, different voltage levels, different connection points, demand levels, energy quantities and times of use.

1237. Sections 7.3 and 7.4 of the Access Code set out the objectives for pricing methods, as follows:

> 7.3 Subject to sections 7.5, 7.7 and 7.12, the pricing methods in an access arrangement must have the objectives that:
>
> (a) reference tariffs recover the forward-looking efficient costs of providing reference services; and
>
> (b) the reference tariff applying to a user:
>
> (i) at the lower bound, is equal to, or exceeds, the incremental cost of service provision; and
>
> (ii) at the upper bound, is equal to, or is less than, the stand-alone cost[173] of service provision.
>
> 7.4 Subject to sections 7.5, 7.7 and 7.12, the pricing methods in an access arrangement must have the objectives that:
>
> (a) the charges paid by different users of a reference service differ only to the extent necessary to reflect differences in the average cost of service provision to the users; and
>
> (b) the structure of reference tariffs so far as is consistent with the Code objective accommodates the reasonable requirements of users collectively; and

[173] The Access Code defines stand-alone cost of service provision as "in relation to a *user* or group of *users*, a *covered service* and a specified period of time, means that part of *approved total costs* that the *service provider* would incur in providing the *covered service* to the *user* or group of *users*, for the period of time if the *covered service* was the sole *covered service* provided by the *service provider* and the *user* or group of *users* was the sole *user* of group of *users* supplied by the *service provider* during the specified period of time."

(c) the structure of reference tariffs enables a user to predict the likely annual changes in reference tariffs during the access arrangement period; and

(d) the structure of reference tariffs avoids price shocks (that is, sudden material tariff adjustments between succeeding years).

1238. Section 7.5 of the Access Code requires that the Economic Regulation Authority (ERA), in reconciling any conflicting objectives for the pricing methods or determining which objective is to prevail, should have regard to the Access Code objective, and where necessary must permit the objectives of section 7.3 to prevail over the objectives of section 7.4.

1239. Section 7.6 of the Access Code provides guidance for establishing components of tariffs:

> 7.6 Unless an access arrangement containing alternative pricing methods would better achieve the Code objective, for a reference service:
>
> (a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand; and
>
> (b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.

1240. Section 7.7 of the Access Code requires that tariffs be established as "postage stamp" charges in certain cases as follows:

> 7.7 The tariff applying to a standard tariff user in respect of a standard tariff exit point must not differ from the tariff applying to any other standard tariff user in respect of a standard tariff exit point as a result of differences in the geographic locations of the standard tariff exit points.

1241. Section 7.9 of the Access Code provides for "prudent discounts" to be made available to some users:

> 7.9 A service provider may propose in its access arrangement to discriminate between users in its pricing of services to the extent that it is necessary to do so to aid economic efficiency, including:
>
> (a) by entering into an agreement with a user to apply a discount to the equivalent tariff to be paid by the user for a covered service; and
>
> (b) then, recovering the amount of the discount from other users of reference services through reference tariffs.

1242. In sections 7.9 and 7.10 of the Access Code, "equivalent tariff" means:

(i) for a reference service – the reference tariff; and

(ii) for a non-reference service – the tariff that it is reasonably likely would have been set as the reference tariff had the non-reference service been a reference service.

1243. Section 7.10 of the Access Code provides for discounts for users connecting distributed generation plant:

> 7.10 If a user seeks to connect distributed generating plant to a covered network, a service provider must reflect in the user's tariff, by way of a discount, a share of any reductions in either or both of the service provider's capital-related costs or non-capital costs which arise as a result of the entry point for distributed generating plant being located in a particular part of the covered network by:
>
> (a) entering into an agreement with a user to apply a discount to the equivalent tariff to be paid by the user for a covered service; and

(b) then, recovering the amount of the discount from other users of reference services through reference tariffs.

1244. Section 7.11 of the Access Code requires an access arrangement to include a detailed policy setting out how discounts under sections 7.9 and 7.10 will be implemented, including a detailed mechanism for determining when a user will be entitled to receive a discount and for calculating the discount to which the user will be entitled.

1245. Section 7.12 of the Access Code requires that the value of any tariff equalisation contributions be recovered as a tariff component from users of the distribution network:

> 7.12 If an amount is added to the target revenue under section 6.37A and is intended to be recovered from users of reference services through one or more reference tariffs, then the recovery must have the objective of:
>
> (a) applying only to users of reference services provided in respect of exit points on the distribution system; and
>
> (b) being equitable in its effect as between users referred to in section 7.12(a); and
>
> (c) otherwise being consistent with the Code objective.

1246. Section 5.1(f) of the Access Code requires an access arrangement to include a Price List in accordance with the requirements of chapter 8 of the Access Code. A "price list" is defined in the Access Code as a schedule of reference tariffs.

1247. Chapter 8 of the Access Code sets out the requirements and processes for a service provider to submit Price Lists to the ERA for approval and for the ERA to approve or not approve a proposed Price List.

1248. Section 8.1 of the Access Code requires that the service provider must submit a proposed Price List to the ERA at least 45 business days before the start of each pricing year other than the first pricing year. A proposed Price List must be accompanied by Price List Information. "Price List Information" is defined as a document that would reasonably be required to enable the ERA, users and applicants to understand how the service provider derived the elements of the proposed Price List; and assess the compliance of the proposed Price List with the access arrangement.

1249. Sections 8.2 to 8.6 of the Access Code sets out the process for the ERA to approve or not approve a proposed Price List. The ERA is obliged to approve a proposed Price List if it determines that the proposed Price List complies with the price control and pricing methods in the service provider's access arrangement.

1250. Sections 8.7 and 8.8 of the Access Code require a service provider to submit Price Lists to the ERA, even if the access arrangement does not require the service provider to submit Price Lists to the ERA for approval. In these circumstances, the role of the ERA is to publish the submitted Price List and Price List Information.

Current access arrangement

1251. Pricing methods are included in the current access arrangement at section 6 and include the formula for determining maximum target revenue each year, the allocation of costs to particular reference services and the pricing structure of each reference tariff.

1252. A Price List and Price List Information for the period 1 February 2013 to 30 June 2013[174] was included in the current access arrangement at Appendix F. Subsequent to the approval of the current access arrangement, the Price List was revised to incorporate variations to reference tariff charges made in accordance with the price control for the years 2013/14, 2014/15, 2015/16 and 2016/17.

1253. The current access arrangement includes a side constraint formula based on the CPI, the percentage change in the approved target revenue, correction factors (the under or over-recovery of revenue and the TEC) and an additional two per cent. The side constraint limits annual changes to individual reference tariffs during the access arrangement period to mitigate the effects of price shocks during an access arrangement period.

Western Power's initial proposal

1254. Apart from making changes to reflect the fourth access arrangement period (AA4), Western Power did not propose any amendments to the pricing methods[175] set out in section 6 of its proposed revised access arrangement.

1255. Sections 6.5.14 and 6.5.16 were added to provide for annual updates to the weighted average cost of capital to be taken account of in the side constraint.

1256. Western Power included proposed Price Lists and Price List Information for 2017/18[176] and 2018/19[177] in its initial submission. Western Power noted:

> Due to the one year delay in commencement of the AA4 revenue recovery, the revenue caps for 2017/18 are treated slightly differently. In the normal course of events, there would be a revised Price List and Price List Information produced for 2017/18, and these documents would outline the calculation of the revenue target for the year …, including a calculation of the revenue adjustment factor (known as the k-factor). The versions of these documents (Appendix F.1 and F.2 to the proposed access arrangement) are the 2016/17 Price List reproduced, without any adjustments made for the k-factor. The 2016/17 Price List is adopted as the 2017/18 Price List absent a different Price List produced in April 2017 and approved by the ERA in May 2017 due to the delay to the AA4 process.

1257. Western Power's Proposed Price List and Price List Information for 2018/19 set out the tariffs it proposed to commence on 1 July 2018 based on the target revenue in its initial submission.

1258. Western Power summarised its proposed amendments to reference tariffs as:

> We are proposing the following changes to reference tariffs for the AA4 period:

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[174] As the access arrangement was approved after the commencement of the 2012/13 financial year, the Price List for 2012/13 did take effect until 1 Feb 2013. The prices were set in such a way that the total revenue earned throughout 2012/13 was equal to the 2012/13 approved revenue caps.

[175] With the exception of adding the proposed new reference services (D1 to D4) to clause 6.32 which specifies the costs relating to reference services are allocated so that those costs can determine the relevant reference tariff in a cost reflective manner.

[176] Appendix F.1 and F.2 of Western Power's proposed revisions to the Access Arrangement.

[177] Appendix F.3 and F.4 of Western Power's proposed revisions to the Access Arrangement.

- Introducing two new time of use tariffs
- Introducing two new demand-based tariffs
- Modifying peak/off-peak time periods in the existing RT5 and RT6 demand tariffs to reflect the time periods in the new time of use tariffs
- Modifying existing demand-based tariffs for medium to large businesses (RT5-RT8) to allow for bi-directional flows;
- Recovering Tariff Equalisation Contribution (TEC) from the fixed component of tariffs rather than the variable component of most tariffs."

1259. Western Power's proposed Price List Information for 2018/19 included changes to metering charges and the excess network usage charge. It also noted that future changes were likely for streetlight tariffs.

Submissions on Western Power's initial proposal

1260. Submissions from Perth Energy, Mr Noel Schubert, Community Electricity, Emergent Energy, Mr Craig Hosking, Energy Networks Australia, Synergy, Bluewaters, CdL Advisory, WACOSS and WALGA on Western Power's initial proposal all included comments on Western Power's proposed pricing methods and tariffs.

1261. The submissions included support for more cost-reflective tariffs. However, views on whether Western Power's proposal achieved this varied. Alternative suggestions for developing prices were also put forward together with specific comments on Western Power's proposed tariffs. These are discussed under Considerations of the ERA.

Considerations of the ERA

Pricing methods in the access arrangement

1262. The ERA has considered pricing methods separately from the application of the pricing method. This section considers the pricing methods. The following section, *Proposed 2018/19 Price List and Price List Information*, considers the application of the pricing methods.

1263. Western Power's pricing methods were set out in section 6 of the initial proposed access arrangement and specific details were set out in the price list information included as Appendix F.2 and F.4 of the initial proposed access arrangement.

1264. As set out in the price list information, and consistent with previous access arrangements, Western Power determined the value of individual reference tariffs and the individual charges of the reference tariffs by applying a cost allocation model. Under the model, the capital and non-capital components of total costs are allocated to cost pools and location zones, then to customer groups corresponding to reference services, and to charges that make up each reference tariff. Costs are allocated according to:

- the characteristics of a user at a connection point and measures of each user's proportional share of use of the network relative to other users; and
- the amount of costs that can be allocated to a user at a connection point such that the total charges paid by the user under a reference tariff lie between the

incremental cost of service provision and the stand-alone cost of service provision.

1265. This method is consistent with the requirements of 7.3(a) of the Access Code that reference tariffs must recover the forward looking efficient costs of providing reference services and 7.3(b) that requires tariffs to be between the stand-alone and incremental cost of service.

1266. With the exception of metering costs considered below, Western Power has not materially changed its cost assumptions and allocation method since the first access arrangement.

1267. The tariffs offered and the structure of those tariffs have also not changed materially since the first access arrangement.

1268. Mr Schubert's submission on Western Power's initial proposal noted:[178]

> Network tariff and franchise customer retail tariff reform in WA has been minimal over the last 23 years since the very effective tariff reform program that was in progress up to 1994 in WA. … Most residential and small business customers have remained on non-cost-reflectively structured flat electricity tariffs over these many years with little or no structural reform.

1269. The role of the ERA in approving pricing methods proposed by Western Power is to assess whether the pricing methods satisfy the objectives for pricing methods under the Access Code. As section 6 of Western Power's initial proposed access arrangement included all of the requirements set out in Access Code requirements, and the price list information is based on these requirements, the ERA's draft decision found that Western Power's pricing methods were consistent with the Access Code.

1270. Stakeholder submissions on Western Power's initial proposal commented on the lack of pricing and tariff reform and included suggestions for more efficient tariffs. The Access Code does not provide for the ERA to approve structures of reference tariffs to the level of detail that would enable the ERA to impose particular tariff structures such as those proposed in submissions.

1271. As discussed in the section on price control, the ERA considered Western Power's current price control mechanism does not incentivise Western Power to develop more efficient tariff structures. The ERA required Western Power to amend its price control. The ERA considered exposing Western Power to demand risk would provide incentives for it to develop more efficient tariff structures.

1272. It was recommended that Western Power consider the following suggestions for developing more efficient tariffs.

1273. Submissions on Western Power's initial proposal highlighted the problems that arise from the current structure of tariffs. Mr Schubert submitted:[179]

> A key contributor to the rapid take-up of alternative technologies like photovoltaic (PV) systems by customers is also the lack of cost-reflectively structured network and retail

[178] Mr Noel Schubert, *Submission re: Proposed Revisions to the Western Power Network Access Arrangement – AA4*, 11 December 2017, p. 2.

[179] Mr Noel Schubert, *Submission re: Proposed Revisions to the Western Power Network Access Arrangement – AA4*, 11 December 2017, p. 3.

> tariffs. Existing flat, energy-based tariffs provide greater financial incentives to take up these technologies, and air conditioners too … than is economically efficient.
>
> The widely used flat (non-time-varying) energy-based network and retail tariffs (without a demand component to reflect customer demand that drives network and generation capacity capex) are a key reason that customers install solar PVs and avoid more (bill) costs than is economically efficient.

1274. Mr Hosking submitted:[180]

> … Western Power's network tariffs, applied to most electricity customers, charge kWh energy rates …. These kWh energy based network tariffs result in economic inefficiencies in the electricity supply system and cross-subsidies between customers, because they do not match the network cost structure.

1275. Emergent Energy submitted that the current tariff structures are not adequate for the technological disruption that is occurring:[181]

> Another aspect of technological disruption is that the rules and regulations of the sector are seldom appropriate to manage the new technology entrants. In other words, the playing field is not initially level. Nor should it be expected to. Technological disruption is characterised as being unexpected and sudden. In the case of online retailers, already boasting many advantages over their traditional competitors, the initial absence of GST levied against online sales provided an unfair advantage over the bricks and mortar incumbents. Similarly, in the electricity supply sector, the existing structure of (fixed and variable) pricing, for so long an adequate (if not particularly sophisticated) method of recovering the costs of providing the service, now place incumbents at a disadvantage.

1276. Stakeholders considered changes in pricing and tariff structures are necessary to deliver efficient outcomes.

1277. Mr Schubert considered:[182]

> The introduction of more cost-reflectively structured, time-varying network and retail electricity tariffs would start to drive more economically efficient outcomes, including the beneficial application of energy storage such as batteries.

1278. Emergent Energy considered change is required but noted issues that could arise and the need for policy makers to respond to and influence change:

> … new pricing mechanisms are required to better align with recovery of the fixed cost to Western Power in maintaining the network… but if those pricing mechanisms are properly structured to incentivise even greater efficiency (and lower costs to consumers), then by implementing them, Western Power faces a likely devaluation to its business. Similarly, if not structured effectively, higher fixed prices will stymie the uptake of BTM assets to the detriment of network efficiency.
>
> The manner in which properly structured price incentives are to be implemented must cut across a number of regulatory and policy levers. While the Authority has only a mandate to deal with those levers provided under the Access Code, it should be recognised that as technology changes the nature of the network, a collaborative

[180] Mr Craig Hosking submission, *Submission to the ERA Regarding Western Power's AA4 Proposal*, 11 December 2017, p. 1.

[181] Emergent Energy Submission, 8 December 2017, p. 2.

[182] Mr Noel Schubert, *Submission re: Proposed Revisions to the Western Power Network Access Arrangement – AA4*, 11 December 2017, p. 3.

response from policy makers and rule makers alike is required to respond to, influence and even harness this change.

1279. Specific alternative tariff structures were proposed by Mr Hosking who recommended Western Power should implement demand based charges using $/kilo-volt-ampere (kVA) and that it should review its cost allocation assumptions:[183]

> By using kWh energy rates for the network tariffs, Western Power is promoting that retailers and customers reduce their network kWh consumption, even when there is no reduction to network kVA demand, which is the primary incremental network cost driver. This mismatch between network prices and costs leads to economic inefficiencies in the electricity supply system and cross-subsidies between network electricity customers.
>
> Western Power should recast the network tariffs to properly reflect the actual network cost structure i.e. $/customer per annum and $/kVA per annum demand. Prior to recasting the network tariffs, Western Power should re-examine its Fixed ($/customer per annum) verses Variable ($/kVA per annum) allocation to the distribution cost groups, especially considering the weighting of Western Power's line and underground cable assets and their true Fixed verses Variable (incremental) cost nature.

1280. Mr Hosking also suggested how Western Power could implement these charges, including for users that do not have meters that record demand:[184]

> Practically, Western Power is able to restructure its distribution network tariffs fairly easily, because it only sells to retailers and not directly to the distribution electricity customers. For electricity customers without kVA demand metering, Western Power can use the customer group any time maximum demand (ATMD) to determine the appropriate $/kVA rate to be applied and thereby the total aggregated charge to apply to each retailer, depending on their customer types.
>
> Thus Western Power's revenue would remain the same, retailers would receive the right cost signals to develop retail tariffs that closely matched the network cost drivers, and electricity customers would be encouraged to examine ways and technologies for reducing their network peak kVA demand.

1281. Emergent Energy provided suggestions to implement a new charging structure that would encourage users to install smart meters themselves:[185]

> Customers can be incentivised, via a "carrot and stick" approach, to install smart meters themselves. Customers have already spent over half a billion dollars on BTM assets over the past five years and are likely to more than triple that expenditure over the next five. Their ability and propensity to outlay capital for the superior utility brought by investing in new technology has been demonstrated and should be harnessed by policy makers.
>
> …
>
> By deeming a peak demand level for individual customers, based on some formula utilising historical usage patterns, customers will pay a higher, but fair fixed price to access the grid. However, customers will have the opportunity (and incentive) to install a smart meter in order to set an actual peak demand level, rather than have it deemed. They will be further incentivised to modify their consumption, as well as to adopt BTM storage earlier than they otherwise might, which will reduce their actual peak demand. They will pay less to use the network because the more efficient network will cost less

[183] Mr Craig Hosking submission, *Submission to the ERA Regarding Western Power's AA4 Proposal*, 11 December 2017, p. 1.

[184] Mr Craig Hosking submission, *Submission to the ERA Regarding Western Power's AA4 Proposal*, 11 December 2017, p. 2.

[185] Emergent Energy Submission, 8 December 2017, pp. 9-10.

to operate. This would be a significant exercise to implement, but it will have the potential for dramatic impacts around the way in which customers access electricity supply services into the future. Multiple retail models are possible. As seen in the telecoms and internet markets, ownership of phones and modems quickly passed from the service provider to the customer under lease, outright ownership, [bring your own] or other mechanisms. And as grid defection becomes a reality, network owners face the increasing likelihood that electricity meters will disappear from their asset base at any rate. As the role of networks change and regulated revenue drops, it is preferable to not embark on an exercise that would require a large new set of assets (smart meters) to be added to the already overweight distribution asset base.

1282. Other matters raised in submissions on Western Power's initial proposal included postage stamp pricing, charging energy exported from behind the meter generation for use of the network and affordability.

1283. Emergent Energy discussed issues arising from the current Access Code requirement to use postage stamp tariffs for users with energy consumption less than 1 Mega Volt Amp (MVA):[186]

> Where Western Power eschews 'conventional network management', or poles and wires, for new technology (such as distributed generation and storage), it is moving from a natural monopoly service model into what is a very competitive sector. If it is more efficient to install distributed generation and storage, rather than replace aging poles and wires, should Western Power be able to replace one with the other on its asset base? The market for providing distributed generation and storage services is not a natural monopoly. But only Western Power has access to the 'benefit' of the obligation-cost of replacing an existing monopoly asset.
>
> This issue raises questions about the ability to apply 'postage stamp' tariffs to all consumers. It also raises questions about whether a consumer at the end of a remote distribution line, which has enjoyed subsidised (postage stamp) tariffs, should be allowed to leave the grid for an alternative supply model at a point in time when the network assets are still useful.

1284. Bluewaters submitted that behind-the-meter exporters should be charged for using network, as is the case for other generators:[187]

> Bluewaters notes that one of the contributory factors for the expected lack of growth in Western Power network capacity demand is the emergence of the BTM technologies. Bluewaters also notes that, under the proposed Western Power tariff structure, there is no transmission network cost recovery from these BTM facilities. This is despite the fact that these BTM facilities require access to the transmission networks (mostly via the distribution network) due to the intermittent nature of these generation facilities.
>
> Bluewaters considers this creates an inequitable situation where BTM facilities get free access to the transmission network at the expense of the non-BTM facilities. Bluewaters considers this to be an inefficient allocation of costs and can potentially distort the investment signal in the SWIS. Bluewaters also notes that the rapid growth of BTM facilities will only magnify this problem.
>
> Distortion in investment signal can compromise the adequacy of generation mix in the SWIS, in turn gives rise to various economics and technical issues (inertia and intermittency problems, for examples). This can compromise the reliability and security of the power system.

[186] Emergent Energy Submission, 8 December 2017, p. 13.

[187] Bluewaters Power, *Response to issues paper on proposed revisions to the western power network access arrangement (2017/18 to 2021/22 - aa4)*, 11 December 2017, p. 2.

> Bluewaters considers, to the extent which Western Power's network is required to support the efficient generation investment signal discussed above, cost recovery of the network assets from the BTM generation should be reflected in the principles underpinning the pricing method in the Access Arrangement. Bluewaters also recommends that such cost recovery be in turn reflected in the Western Power's tariff structure.

1285. WACOSS discussed the significant effect electricity retail prices have on households, particularly those with low incomes. WACOSS noted that "low income earners may be forced to forsake services such as water or electricity, which are essential to maintaining a reasonable standard of living, in order to feed themselves or to keep a roof over their head".

1286. The ERA considers the suggested alternatives in stakeholder submissions for pricing methods have merit and could lead to more efficient tariffs. However, the Access Code does not provide for the ERA to approve pricing methods to the level of detail that would enable the ERA to impose pricing methods such as those proposed in submissions.

1287. The ERA considers that modifying Western Power's price control will encourage Western Power to develop its pricing methods and ensure its tariffs are set more efficiently.

Proposed 2018/19 Price List and Price List Information

Target revenue cap and side constraint formula

1288. As set out in its draft decision, the ERA did not approve the transmission or distribution network target revenue proposed by Western Power. Consequently, Western Power was required to amend its proposed revised Price List and Price List Information for 2018/19 to be consistent with the approved transmission and distribution network target revenue.

1289. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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.

1290. In its revised proposal, Western Power has not accepted draft decision required amendment 16. Western Power submits:[188]

> 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.
>
> 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.
>
> 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).

[188] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p.148.

1291. The ERA has not approved Western Power's revised proposed target revenue. The commencement date for the new tariffs will also need to be amended. As set out in the Introduction, for the purposes of the final decision, the ERA has assumed the new tariffs will commence on 1 February 2019. Consequently, Western Power will need to update the 2018/19 Price List and Price List Information to be consistent with the target revenue approved in the final decision and a commencement date of 1 February 2019.

1292. The ERA has also required Western Power to add new reference services, modify existing reference services and amend tariff structures. The price list will need to be amended to reflect all of these changes.

Required Amendment 19

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 final decision and apply them from a commencement date of 1 February 2019. Western Power must also amend the 2018/19 Price List and Price List Information for other relevant changes in the final decision on reference services and tariff structures as set out in Pricing Methods, Price List and Price List Information.

1293. The draft decision also required Western Power to update Table 16 of Appendix F.4 (2018/19 Price List Information), which demonstrates compliance with section 7.3(b)(i) and (ii) of the Access Code and Table 18, which demonstrates compliance with section 7.6 of the Access Code. Western Power had only included distribution tariffs in these tables. The draft decision required Western Power to expand the tables to include transmission tariffs.

1294. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

1295. In its revised proposal, Western Power states it has accepted draft decision required amendment 17 in principle with modifications. Western Power submits:

> 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).
>
> Consistent with each of the previous access arrangements, we have not detailed the transmission reference tariffs in either of these tables.
>
> 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.

> 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.
>
> 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.
>
> 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.

1296. A review of the revised 2018/19 Price List Information identified that Western Power has added a new section 6.5 headed *Compliance with sections 7.3(b) and 7.6 of the Code*:

> Section 7.3(b) of the Code requires that reference tariffs are set between the incremental and stand-alone costs of service provision. For transmission reference tariffs, Western Power asserts that the pricing method described above, in particular the application of the T-price approach to tariff setting, ensures that tariffs remain between these two bounds.
>
> As a result, section 7.6 of the Code, which requires that variable components of tariffs recover the incremental costs of service provision, is also deemed to be satisfied.

1297. This assertion does not provide evidence that the transmission tariffs are set between the incremental and stand-alone costs of service provision, or that the variable components of transmission tariffs recover the incremental costs of service provision. Western Power must be able to demonstrate this to be compliant with sections 7.3(b) and 7.6 of the Access Code.

Required Amendment 20

Western Power must amend the 2018/19 Price List and Price List Information to include tables similar to those provided for distribution tariffs, to demonstrate that transmission tariffs are set between the incremental and stand-alone costs of service provision and that the variable components of transmission tariffs recover the incremental costs of service provision.

1298. As set out in the draft decision section on price control, the ERA required amendments to remove the correction factor for under or over recovery of target revenue from prior periods from the price control mechanism. As the current side constraint formula includes the correction factor, the side constraint formula was also required to be amended.

1299. The ERA's draft decision required the following amendment to Western Power's proposal.

> **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.

1300. In its revised proposal, Western Power has not accepted draft decision required amendment 18. Western Power submits:[189]

> 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.
>
> 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.

1301. As set out under the section on Price Control, the ERA's final decision has required Western Power to remove the correction factor for under or over recovery of target revenue from prior periods from the price control mechanism. As the current side constraint formula includes the correction factor, the side constraint formula must also be amended.

Required Amendment 21

Western Power must amend the side constraint formula to remove the correction factor for under or over recovery of target revenue from prior periods.

Fixed and variable charges

1302. Under section 7.6 of the Access Code, the incremental cost of service provision should be recovered by tariff components that vary with usage or demand and the remaining costs should be recovered by tariff components that do not vary with usage or demand, unless an alternative method would better achieve the Access Code objective.

1303. As discussed above, stakeholders suggested changing charging structures to increase the level of fixed charges.

1304. In its initial proposal, Western Power noted that during the third access arrangement period (AA3) it increased the proportion of revenue recovered by fixed charges:

> In line with the premise of cost reflectivity, it is reasonable that the fixed component of a network tariff reflects the fixed costs of running the network. Historically, the fixed charges increased from 27 per cent for an average bill to 40 per cent over AA3. It should be noted that these fixed charge increases were offset by variable charge decreases, meaning that the change is revenue neutral.

1305. In Attachment 11.1 to its access arrangement information, Western Power provided the following comment on its ability to recover revenue through fixed charges:

[189] Western Power Revised AA4 Proposal Response to the ERA's draft decision 14 June 2018, pp. 149-150.

> Recovering more revenue on a fixed basis has an appeal to Western Power, particularly from a revenue stability point of view. However, there are a number of reasons why we have not increased the fixed charge much higher than current levels.
>
> - The variable components give Western Power the opportunity to send signals around the most efficient use of the network. A fully fixed tariff structure removes this option.
> - Section 7.6(a) of the Access Code requires that the incremental cost of service provision is recovered by variable components. This limits the extent to which tariffs can be fixed.

1306. Table 18 of Western Power's initial proposed 2018/19 Price List Information showed the revenue recovered from variable tariff components for all reference tariffs is approximately double Western Power's estimate of the incremental cost of service for each reference tariff. The proportion of fixed charges could be increased substantially and still be compliant with section 7.6(a) of the Access Code.

1307. However, the ERA recognised that any changes between fixed and variable charges would need to be carefully structured and managed. Submissions from CdL Advisory and Emergent Energy provided comment on this.

1308. CdL Advisory supported cost-reflective pricing but noted:[190]

> … it should be implemented with due regard to the broader regulatory and technological context particularly concerning rooftop solar, battery backup and feed in tariffs.

1309. Emergent Energy submitted:[191]

> … it is likely that the prevailing fixed and variable pricing structure is not appropriate, given the new technological forces re-shaping the sector. A higher fixed portion, offset by lower variable portion may provide a more appropriate cost recovery structure, given the previous requirement to investment in peak demand infrastructure. But higher fixed tariffs must be implemented in a manner that provides incentives to customers to change their behaviour. That is, fixed tariffs should be attributed to a customer's contribution to peak demand. By increasing fixed tariffs without any accompanying price signal, Western Power is simply recovering costs when those costs are becoming inefficient due to technological changes to the electricity supply model. [page 14]

1310. The amendments to the price control will expose Western Power to demand risk and encourage Western Power to develop more efficient tariff structures, including the balance between fixed and variable charges and the basis of setting any fixed charges.

Tariff Equalisation Contribution

1311. A large component of Western Power's fixed costs is the Tariff Equalisation Contribution (TEC). An amount of $167 million was gazetted for the 2017/18 year which is around 15 per cent of Western Power's proposed operating expenditure for the distribution service. Currently the TEC is collected through a combination of fixed and variable components of the network tariffs.

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[190] CdL Advisory, 4 December 2017, p. 2.

[191] Emergent Energy Submission, 8 December 2017, p. 14.

1312. In its initial submission for AA4, Western Power proposed to recover the TEC entirely from fixed components of network tariffs:[192]

> For most tariffs, the TEC is currently fully recovered from the variable network tariff components. This is despite the TEC being to all intents and purposes a fixed and unavoidable cost, determined by State Government. Therefore Western Power considers it reasonable that the TEC should be wholly collected via the fixed tariff component. Recovering the TEC from fixed tariff components would also mean the regional subsidy is shared equally by all Western Power customers.
>
> In most cases, customers will be no worse off as a result of the increased fixed charges. This is because there would be an offsetting decrease in variable charges.

1313. Submissions from Synergy and Emergent Energy supported this approach. Synergy considered recovering the TEC through reference service fixed charges rather than through reference service variable charges was consistent with section 7.6 of the Access Code. Emergent Energy noted:[193]

> Given the decline in demand (and variable revenue risk), and given the TEC is an obligation imposed on Western Power by the government, then it is appropriate that Western Power is not exposed to TEC recovery risk.

1314. However, Community Electricity considered the proposal was inconsistent with the Access Code as it would result in an inequitable allocation of the TEC between users:[194]

> … clause 7.12b which requires the TEC to be allocated equitably between users; specifically, the proposal is that the most vulnerable members of society will unavoidably bear the charge of subsidising affluent users benefitting from the subsidy. Further, this cost would be born by Synergy, who could only pass it through to customers at the direction of government, which controls retail tariffs.

1315. After lodging its proposed revisions to the access arrangement, Western Power advised the ERA that:[195]

> Following consultation with our shareholder and the Department of Treasury, we have decided not to proceed with the proposed change to the TEC at this time as we believe it would be prudent to allow more time to fully consider any forthcoming market reforms. As this is essentially an administrative change to the recovery of the TEC, we will revisit it at a later date, as required.

1316. In the draft decision the ERA considered, given the fixed nature of the TEC, recovering it via fixed charges would be consistent with section 7.6 of the Access Code. 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.

1317. Section 7.12 provides for the TEC to be recovered from users of reference services through one or more reference tariffs. The recovery must apply only to users of reference services provided in respect of exit points on the distribution system, be

[192] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 254.

[193] Emergent Energy, 8 December 2017, p. 15.

[194] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, p. 6.

[195] 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, p. 2.

equitable in its effect between users and be consistent with the Access Code objective.

1318. The users of Western Power's network are predominantly retailers, generators and large users with direct connections to the transmission system. Consequently, the relevant users for allocation of the TEC are retailers. The ERA considered the requirement is for Western Power to ensure the allocation is equitable between those retailers.

1319. Because the TEC can vary each year, depending on the value gazetted by the government, it contributes to price uncertainty. Recovering the TEC through variable charge components compounds the uncertainty as it will generally be necessary to adjust prices for under or over recovery of the TEC in the previous period. Developing a fixed charge based on an equitable allocation between retailers could provide a more predictable and transparent charge for users. Users would continue be able to determine how they recovered these costs in their retail tariffs.

1320. In the draft decision, the ERA considered there is a range of options available to Western Power to recover the TEC which would be compliant with the requirements of the Access Code.

1321. Synergy's submission on Western Power's initial proposal raised concerns regarding which customers are charged the TEC. It submitted that not allocating the TEC to distribution customers that use more than 7,000 kVA was not consistent with section 7.12 of the Access Code.

1322. As set out in the Price List Information, historically Western Power has not allocated TEC costs to users with demand greater than 7,000 kVA as these users can usually choose between a transmission or distribution connection. As the TEC does not apply to transmission customers, Western Power considered that charging the TEC to distribution connected users would create a perverse incentive for users to transition to being transmission connected due to the additional charges. The variable demand charge between 1,000 and 7,000 kVA is negative so that when added to the fixed demand charge users with demand greater than 7,000 kVA do not pay any TEC costs.

1323. The ERA considered this approach to be reasonable and consistent with the requirements of section 7.12 of the Access Code to allocate costs equitably between users.

1324. Synergy's submission on the draft decision raised this issue again.[196]

> The ERA in its draft decision considers the application of a TEC charge to distribution connected users with demand greater than 7,000 kVA would create a perverse incentive for those users to transition to being transmission connected because these users are generally able to choose between a transmission or a distribution connection.
>
> Synergy notes the ERA is required to have regard to the Access Code objective and the matters described in section 26 of the ERA Act in performing its functions under the Access Code. However, in Synergy's view, it is not open to the ERA to depart from the objective described at section 7.12 of the Access Code. That objective is to ensure that if an amount is added to the target revenue under section 6.37A of the Access

[196] Synergy submission on draft decision, June 2018, pp. 45-46.

Code and is intended to be recovered from users of reference services through one or more reference tariffs, then the recovery must have the objective of:

- applying only to users of reference services provided in respect of exit points on the distribution system (section 7.12(a) of the Access Code);
- being equitable in its effect as between the users referred to in section 7.12(a) (section 7.12(b) of the Access Code); and
- otherwise being consistent with the Access Code objective (section 7.12(c) of the Access Code).

In Synergy's view, the objective in section 7.12 of the Access Code describes the class to whom the cost recovery objective is to have application in section 7.12(a) of the Access Code. The effect as between the members of the class is to be equitable in accordance with section 7.12(b) of the Access Code. Finally, section 7.12(c) of the Access Code requires the objective must "otherwise" be consistent with the Access Code objective. Synergy takes the term "otherwise" in this context not as a term of limitation of sections 7.12(a) or 7.12(b) but instead to mean "provided that sections 7.12(a) and 7.12(b) of the Access Code is satisfied...".

The requirement of sections 7.12(a) and 7.12(b) of the Access Code is unambiguous. The class to which the objective and the principle of effective equity applies is the class of all users of reference services provided in respect of exit points on the distribution system.

In Synergy's view, therefore, it is not open for the ERA to determine a narrower class of users or determine that costs should not be recovered equitably across that class of users in the unlikely event that some end-users (who currently or in the future may also be distribution connected end-users) may at some stage in the future be incentivised to switch to transmission connections.

Synergy considers the ERA's apprehension of such a switch to transmission connections is unwarranted because such an event is highly unlikely. A switch from distribution to transmission connection on the part of an end user at 7,000 kVA or above would, in most cases, either:

- require a relocation of plant and equipment to an area where transmission connection is a possibility; or
- require a large capital contribution to bring a transmission connection to an existing facility.

In view of the foregoing, Synergy does not consider applying the TEC to all users of reference services provided in respect of exit points on the distribution network would be inconsistent with the Access Code objective but in any event, application of the TEC to all such users is in Synergy's view an express requirement of section 7.12 of the Access Code. Synergy therefore requests the ERA reverse its draft decision in respect of this matter and makes a decision in accordance with the position advocated by Synergy in its earlier submissions.

1325. Having reviewed the matters raised by Synergy, particularly the points it makes regarding the unlikelihood of such users being able to switch to a transmission connection just to avoid paying the TEC, the ERA agrees these users fall within the class of users that are required to pay the TEC specified in section 7.12 of the Access Code. Consequently, Western Power must amend the price list information and price list to allocate TEC charges to these users in order to be compliant with sections 7.12(a) and 7.12(b) of the Access Code.

Required Amendment 22

Western Power must include distribution connected users with demand greater than 7,000 kVA in the class of users charged the TEC.

Metering costs

1326. In its initial proposal, Western Power proposed a change in the allocation of metering costs. It proposed moving from multiple prices and structures, to one fixed price for all standard metering services.

1327. Western Power stated:[197]

> Analysis show that for distribution customers, there is very little variation in meter costs based on the type of meter installed. Most of the costs of providing meter services are fixed costs for IT systems, meter testing facilities and labour costs.

1328. Western Power proposed to charge for metering solely through a fixed daily price, and removed the energy consumption components currently included in tariffs. The proposed 2018/19 metering price for all distribution tariffs is $32 per year and for all transmission tariffs is approximately $8,000 per year. The same charge applies regardless of meter type.

1329. Mr Schubert's supported the proposed move to fixed metering charges, noting that metering costs do not vary by energy consumption. Mr Schubert considered the proposed change would remove a distortion that the current variable metering charges cause which results in cross subsidies between customers.

1330. As set out in the section on reference services, the ERA determined that metering services should be separated from the current reference services and that a range of metering services (for each service that is likely to be sought by a significant number of users) should be offered. Western Power was required to develop tariffs for these metering services.

1331. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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.

1332. In its revised proposal, Western Power has not accepted draft decision required amendment 19. Western Power submits:

> 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.
>
> We propose an alternative solution to ensure metering services are more cost reflective. This alternative proposal means that standard metering services (which are

[197] Western Power, *Proposed Access Arrangement, Appendix F.4: 2018/19 Price List Information*, 2 October 2017, p. 46.

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.

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.

1333. As set out in Reference Services, the ERA has required Western Power to specify metering reference services including:

- An accumulation meter manual read every two months
- An interval meter manual read with data provided every two months
- An interval meter manual read with data provided every month
- A one-off interval meter manual read
- An interval meter remote read.

1334. Western Power must develop tariffs and include supporting information on how the costs have been derived and the basis of the tariffs in its price list Information and price list for the required metering reference services.

Required Amendment 23

Western Power must develop tariffs compliant with the Code requirements and include supporting information on how the costs have been derived and the basis of the tariffs in its price list information and price list for the metering services required by the ERA in Reference Services and Non-Reference Services.

Specific tariffs included in the 2018/19 Price List

New time of use and demand tariffs

1335. In its initial proposal, Western Power proposed new residential and commercial time of use services and demand tariffs (RT17 to RT20). Although the new tariffs include peak and off peak time periods, Western Power set charges for each period the same as the residential and commercial anytime energy tariffs (RT1 and RT2). The proposed new commercial demand tariff included a shoulder period which is also priced at the same rate as the commercial anytime energy tariff.

1336. Western Power considered time of use tariffs could reduce peak demand and the need for investment to increase the capacity of the network:[198]

> Time of use tariffs are a potential alternative to the costly option of increasing network capacity. By encouraging customers to use electricity outside of peak times, the tariffs can help reduce the need for network capacity expansion, which saves customers money over the long term. Time of use tariffs can also help customers save money directly, as it provides greater opportunity to control costs by making just a few moderate changes to when and how they use electricity.

1337. Submissions on Western Power's initial proposal from Energy Networks Australia and Change Energy indicated general support for the new tariffs, although Change Energy queried which types of business customers would qualify for the new demand tariff and whether peak demand would be measured each month or on a rolling twelve month basis like the existing high and low voltage metered demand tariffs (RT5 and RT6).

1338. Submissions from Perth Energy, Community Electricity, Synergy and Mr Schubert all raised concerns regarding the proposed new tariffs.

1339. Perth Energy submitted:[199]

> …Western Power Tariffs should be variable driven and offer better price signals to customers in order for them to optimise their use of the network. Perth Energy believes the new time of use tariffs proposed do not go far enough in offering efficient price signals to customers. It is important to note, without changing all the tariffs to time of use it is hard to establish longer term benefits to Western Power. Customers that contribute to high system peaks will not migrate to the new time of use tariffs as they will view this tariff as financial penalty when compared to the existing tariffs. However, customers who do not contribute to the peak demand will migrate to the time of use tariff as they will see cost savings.
>
> The tariffs proposed do not support change in consumer usage patterns, rather they will entrench behaviours that are not in the best interests of the market as a whole. The dichotomy that exists within the proposed tariff structure is that those customers Western Power want to target with the new tariffs will be most resistant to adoption, whereas those customers who do not materially contribute to system peaks may migrate to the new tariff in search of savings. Given this, Perth Energy would question the applicability of the proposed tariff regime.
>
> Perth Energy would propose that Western Power undertake a more holistic tariff reform to develop a structure that will more appropriately provide price signals and incentivise customers to manage their energy consumption more efficiently. Perth Energy is also concerned the new tariffs proposed by Western Power will not yield efficiencies, as it is not clear what the reduction in target revenue is as a result of the implementation of new time of use tariffs.
>
> Perth Energy would like to see an estimate from Western Power on how successful they believe these new tariffs will be and how the new tariff relates to an expected reduction in the amount of revenue it needs to recover over AA4.

[198] Western Power, *Access Arrangement Information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. xxviii.

[199] Perth Energy *Submission to the Economic Regulation Authority regarding Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network (2018-2022)*, November 2017, pp. 13-14.

1340. Submissions from Mr Schubert and Community Electricity raised concerns that Western Power's proposed prices for the new tariffs were identical to existing anytime energy tariffs. Mr Schubert submitted:[200]

> When a new tariff is introduced, ideally it should be set at cost-reflective rates from the start and be applied to customers in an acceptable, managed way to account for the different impacts on customers with different electricity consumption load profiles. I do not support starting the introduction of these new tariffs with rates in each time period that are not cost-reflective.

1341. Community Electricity submitted:[201]

> … there is no point in delivering a price signal that cannot be responded to.
>
> …
>
> …Equally, there is no point developing new tariff options that contain identical prices to existing tariffs but with more time structure, which is effectively of null effect.
>
> …
>
> We challenge Western Power to demonstrate by application to sample load profiles that any of the new tariffs have any practical utility whatsoever.
>
> …
>
> We consider that the proposed tariff reforms are a missed opportunity that do nothing to mitigate the death spiral, and guarantee mal-investment and an eventual price dislocation when the system is forced to reset. We suggest it is preposterous to base a programme of investment in advanced meters on such insubstantial fine-tuning and customer inability to understand or respond to the price signals.

1342. Synergy was also concerned there was insufficient information to evaluate the proposed new tariffs, including the effect on demand and prices:[202]

> Introducing time of use tariffs and demand tariffs for residential and small business customers may result in a large change to their historical electricity costs. The WP proposal notes the intention to manage this impact by setting energy and demand tariffs for RT19 and RT20 so that an average customer would pay the same under a flat rate, time of use or demand based tariff. This in turn raises several questions:
>
> - Will time of use tariffs RT17 and RT18 be established to manage the impact on customers so that customers would pay the same under a flat rate or the time of use tariff? WP's proposal contains no statement to this effect.
> - What is an average customer? New customers typically have lower energy use and different consumption profiles to existing customers because new buildings tend to be designed to maximise energy efficiency and incorporate more energy efficient appliances. If WP is assuming new residential customers have the same average consumption as existing residential customers it is possible they could be over-recovering from existing customers and under-recovering from new customers. This, together with the requirement for new residential and small use customers to face time of use tariffs on a compulsory basis, while allowing existing residential and small use customers to opt in at a future stage, may mean new and existing customers face significantly different network charges on an ongoing basis. Synergy submits this may contravene the Code requirement that tariffs only

[200] Mr Noel Schubert, *Proposed Revisions to the Price Waterhouse Coopers access arrangement- AA4,* 17 December 2017, p. 2.

[201] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, p. 6 para 37, p. 8 para 48, 51, p. 9 para 55.

[202] Synergy, *AA4 submission No. 5: Western Power's proposed price control mechanisms*, 11 December 2017, p. 90.

differ to reflect divergence in the underlying cost of service (section 7.4(a) of the Code).

Synergy therefore submits:

- all residential and small use customers be given the option to choose time of use tariffs (i.e. these tariffs be not compulsory);
- consideration be given to adopting a more comprehensive and systematic approach to determining customer demand for the application of demand tariffs;
- WP's intentions in relation to managing the customer impact for tariffs RT17 and RT18 be more clearly stated; and
- WP's assumptions in relation to the average customer used to calculate time of use and demand tariffs be clarified and published.

1343. Community Electricity raised concerns regarding the structure of the proposed demand tariff and time periods. Community Electricity submitted:[203]

> The proposed tariffs RT19 and RT20 are different from existing tariffs and contain an important feature of defining a new Peak period. …This tariff style suffers the inefficiency that its maximum demand component is reset monthly and has no regard to system conditions; all months are of equal importance where in actuality only one or two drive network investment. Equally, users are penalised for behaviours that are immaterial. While these two new tariffs do create different cost outcomes, they are set to return higher revenue than their counterparts in all practical cases.

1344. Perth Energy considered further work was needed to establish the time periods:[204]

> Perth Energy is of the view the introduction of a 'shoulder' period does not go far enough. Perth Energy believes the tariff structure should be more dynamic to more accurately represent the cost to the network when the network is under stress compared to when it may not be. For example, the 'peak periods' over summer, may be when system stress is at its highest, however the 'peak periods' over autumn and spring may be less intensive on the network. The current tariff structure does not account for this and simply concludes the rewards/penalties, for adjusting consumption down/up exist for all 'peak' periods, irrespective of the state of the network.

1345. The ERA considered there was insufficient information included in Western Power's Price List Information or the material provided with the access arrangement proposal for it to make an assessment of the proposed new tariffs.

1346. In order for the ERA to approve the proposed tariffs, Western Power needed to include its proposed prices for the new services and evidence to demonstrate that the proposed prices are consistent with the Access Code requirements to be based on the forward looking efficient costs and set between the incremental and stand-alone cost of service.

1347. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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

[203] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, p. 8 para 50.

[204] Perth Energy *Submission to the Economic Regulation Authority regarding Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network (2018-2022)*, November 2017, p. 14.

> efficient costs of providing reference services and are set between the incremental and stand-alone cost of service.

1348. In its revised proposal, Western Power states it has accepted draft decision required amendment 20.[205]

> 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.
>
> 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.

1349. The ERA has not been able to identify any information in the Price List Information regarding how the tariffs for the new services have been set. From a review of the Price List, it appears the shoulder periods for D1 and D2 have been set based on the corresponding anytime energy rates. The peak and off peak rates are very slightly above and below the shoulder rates.

1350. The C5 to C8 reference services have been allocated the same tariffs as the existing exit only services.

1351. Further information is required to understand and support the differential rates for the D1 and D2 services. This should also include sufficient information to enable users to understand whether, and if so how, these differential rates may change in future.

Required Amendment 24

Western Power must provide sufficient information in the Price List Information to enable users to understand (and provide evidence for) the differential rates for the D1 and D2 services. This should also include sufficient information to enable users to understand whether, and if so how, these differential rates may change in the future.

Large customer demand tariffs

1352. In its initial proposal, Western Power modified the peak periods for the large customer demand tariffs. Currently, maximum demand for each customer is set based on its rolling twelve month average demand profile. Western Power did not propose changing this.

1353. In its submission on Western Power's initial proposal, Change Energy considered the demand measurement should be based on the monthly, rather than a rolling 12-month peak:[206]

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[205] Western Power Revised AA4 Proposal Response to the ERA's draft decision 14 June 2018, pp. 150-151.

[206] Change Energy's Submission on AA4, 11 December 2017, p. 2.

> Change Energy strongly believes that there needs to be changes to the existing business customer demand based tariffs (RT5 ad RT6) so that the demand measurement is monthly rather than a rolling 12-month peak. This is consistent with demand based tariffs in the NEM and represents a fairer outcome to the customer. As an example, an extended power outage, due to no fault of a customer, may result in a new peak demand when power is restored which the customer must then continue to pay for the next 12 months. Additionally, monthly peak demand will actively encourage customers to try and manage their peak load every month.

1354. Western Power stated it had considered this[207] but decided to leave the tariff structure unchanged:

> Using a 12 month rolling average gives a much clearer signal in terms of the impact that peak demand has on the network. The network is designed to service maximum demand on the network, regardless of whether it is for 1 hour a year or all hours of the year. Switching to monthly demand would soften this signal and will reduce the incentive for customers to be mindful of the impact their demand has at all times.

1355. Perth Energy expressed similar concerns:[208]

> Advanced metering will become an enabler for businesses to innovate their interaction with the network, however the AA4 proposed tariff structure does not accommodate this in any way. For Reference Tariffs 5 to 8; the costs are predominantly fixed on a 12 monthly rolling basis or longer. The lack of accurate and timely price signals for these customers is a concern, and reflects the fact that these customers were not adequately surveyed by Western Power. Western Power is limiting the introduction of innovative energy solutions and products for the Commercial and Industrial sector of the SWIS – the engine room of jobs and economic growth in the state. The full value of products such as peer to peer energy trading or demand side management through the use of batteries will not be achievable, as the price signals proposed in Western Power's proposed tariff structures do not penalise/reward efficient use of the network in a dynamic manner.

1356. Submissions from Mr Schubert and Community Electricity all raised concerns with the structure of the large user demand tariffs.

1357. Mr Schubert considered the tariffs should be modified to make them time based. He considered the current method of applying these demand charges on an anytime basis means:[209]

> Customers whose annual maximum demand coincides with the network annual peak do not have any flexibility or incentive to shift their maximum demand to another time of day to save and reduce loading on the network at its peak demand time - when it matters to Western Power. This means Western Power has to eventually spend more capital on increasing the capacity of the network, increasing costs of supply unnecessarily.
>
> Customers whose annual maximum demand occurs at a time away from the network annual peak are incentivised and will focus their effort and investments on reducing their maximum demand at a time that does not matter to Western Power. It provides no demand reduction benefit to Western Power and reduces its revenue for no gain.

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[207] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, Attachment 11.1.

[208] Perth Energy ***Submission to the Economic Regulation Authority regarding Western Power's Proposed*** *Revisions to the Access Arrangement for the Western Power Network (2018-2022)*, November 2017, p. 14.

[209] Mr Noel Schubert, *Proposed Revisions to the Price Waterhouse Coopers access arrangement- AA4,* 17 December 2017, p. 6.

1358. Community Electricity made similar points and noted inconsistencies in approach across Western Power's range of tariffs:[210]

> We consider that the proposed changes to the contestable RT5 and RT6 tariffs are dysfunctional in that the changes focus on bulk energy rather than instantaneous demand. Furthermore, there is structural conflict between this tariff style and the proposed tariffs RT19 & RT20. We challenge why two notionally similar tariff types would have conflicting structures; RT5&6 are annual anytime maximum demand with no energy charges, while RT19&20 are monthly peak period maximum demand with peak and off peak energy charges. We suggest that both styles are dysfunctional.
>
> The RT5&6 tariff structures have remained unchanged since their inception nearly 20 years ago. While they have always been based on the importance of the maximum annual kVA demand, for a given load profile they charge the same for a load that peaks overnight on a mild autumn day as for a load that peaks in line with the system peak on a hot summer afternoon. Both tariffs apply a 'discount' factor calculated according to the proportion of Peak time consumption (bulk energy opposed to instantaneous demand) and the proposal is to change the Peak period to better represent the summer time load profile. However, this takes no account that PV penetration is depressing the middle-day consumption and that some geographical areas are winter peaking. More importantly, the proposal to redefine the Peak period fails to adopt the innovation contained in RT19&20 of confining the maximum demand to the Peak (new or current) period.
>
> We further note that no reform is proposed in respect of the RT4 tariff …or the RT7&RT8…. The RT4 tariff makes no reference to maximum demand, while the RT7&RT8 are driven entirely by maximum demand and make no reference to the timing of that demand or its relevance to network conditions. Further, RT7&RT8 incur penalties if the CMD is exceeded, regardless of its impact on the system. Similarly to the RT5 & RT6, overnight peaking is classed as the same as summer time. Generators operating under the equivalent tariffs are potentially penalised when called to support the system to their fullest capability.

1359. The ERA considered the matters raised in submissions had merit, however, as discussed above, the Access Code does not provide for the ERA to approve structures of reference tariffs to the level of detail that would enable the ERA to impose particular tariff structures such as those proposed in submissions.

1360. The ERA considered modifying Western Power's price control would motivate Western Power to ensure its tariffs are set efficiently.

1361. Perth Energy's submission on the draft decision refers to the ERA's conclusion in paragraph 1359 above:[211]

> Perth Energy is of the opinion that the tariff structure proposed by Western Power is a barrier to investment in behind the meter energy solutions such as batteries and solar. As such, this barrier is in direct contravention of the Access Code objective to promote competition downstream of the network.
>
> Given the tariff structure is inhibiting the objective of the Access Code; Perth Energy is of the view that the ERA has sufficient remit to make determinations on the structure of reference tariffs, contrary to its statement above.
>
> Payment of network services that is reflective of a customer's network usage, will help facilitate appropriate price signals and drive more informed decisions by customers in regards to alternative energy solutions. Decisions to invest in behind the meter generation (i.e. solar), to invest in energy storage technologies (i.e. batteries) or

[210] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, p. 9 para 52ff.

[211] Perth Energy, Submission to the Economic Regulation Authority regarding ERA's Draft Decision Regarding Western Power's Access Arrangement Proposal (2018-2022), 30 May 2018, p. 8.

> participate in peer to peer energy products are dependent on having accurate and timely pricing signals with respect to network costs. Without accurate pricing signals these investments will not go ahead because customers will continue to pay for a network they will not be using.
>
> In the case of a customer on a reference tariff 5 or 6, they will not see any reduction in their Western Power cost for a minimum of 12 months after making a decision to invest in behind the meter energy solutions. The lack of a timely pay off in respect of lower network costs after investment, is worsening the investment case for these alternative energy solutions.

1362. The ERA has considered the matters raised by Perth Energy. The issue appears to be that users on the high and low voltage metered demand reference services are not able to immediately amend the fixed component of their bill when there is a step change in their requirements as a result of investing in behind the meter energy measures. Instead, it takes 12 months until their reduced usage fully flows through to reduce the fixed charges.[212]

1363. The ERA agrees this element of the structure of the tariff is inconsistent with the Access Code objective as it does not promote competition downstream of the network. It also results in users paying for a level of service they do not require.

1364. The ERA considers this could be addressed by including a mechanism to enable demand to be re-evaluated where it can be clearly demonstrated that future demand will be lower as a result of installing a behind the meter energy measure such as batteries or solar.

Required Amendment 25

Western Power must amend the RT5 and RT6 tariffs to include a mechanism that adjusts the rolling 12-month maximum half-hourly demand where it can be clearly demonstrated that future demand will be lower.

Excess Network Usage Charge

1365. Excess Network Usage Charges (ENUC) apply when a customer exceeds its contracted maximum demand (for a load) or its declared sent out capacity (for a generator). The ENUC applies to the high and low voltage contract maximum demand services and the transmission exit and entry services.

1366. In its initial proposal, Western Power submitted that the charge encourages customers to operate in the contracted values which are used when planning and operating the network:

> However, Western Power recognises that not all instances of exceedance have equal impact. That is, there are some parts of the network where a demand increase won't have an impact on the safety or reliability of the network. The way the ENUC has been applied over the AA3 period does not make that distinction. To address this concern, Western Power is proposing to introduce a more nuanced ENUC. The new charges will consider the location of the customer, making the signal clearer and fairer. Each

[212] Because the charges are based on the rolling 12-month maximum half-hourly demand.

> year, Western Power produces a State of the Infrastructure Report, this document includes discussion on which parts of the transmission network are constrained. It is these areas that the revised ENUC will focus.
>
> In line with the most recent version of the report, for the 2018/19 Price List, the ENUC will be higher for customers in the goldfields region and connected to the Albany substation. Other customers will see a slight reduction in the ENUC.

1367. Mr Schubert's submission on Western Power's initial proposal considered Western Power should remove penalties for customers exceeding their contracted maximum demand (reasonably and in the capacity of the local network) at times that don't matter to the network – i.e. times away from network peak times. Mr Schubert considered this would improve the utilisation of the network and is likely to move customer demand away from network peaks. He also considered this would be preferable to the changes Western Power proposed to make regarding imposing higher penalties for customers in the Goldfields and Albany areas:[213]

> These changes are also preferable to just imposing the high (2.5 times) Excess Network Usage Charges (ENUC) multiplier Western Power proposes to charge RT7, RT8 and TRT1 customers who are on these contract maximum demand (CMD) tariffs in the Goldfields Mining and Albany substation areas – as given in Table 6.19 of the AA4 Appendix F.3 - 2018-2019 Price List. The ENUC multiplier is only 1.0 for all other areas.
>
> I recognise that the Goldfields Mining and Albany areas have very little, if any, spare network capacity available at peak demand times to supply extra, large loads and this is the reason for imposing these high ENUC 'penalties'. However these excess demands are only a problem at these network areas' peak demand times and not at other times.
>
> It would be better, and improve average utilisation of these networks, to incentivise these customers to move their high demands to other times of the day when these networks are not so highly loaded. That is what my recommended demand tariff changes would do. The changes I recommend provide customers with a way of helping to keep the network loads within their respective supply capabilities, at the same time as enabling customers to use more power when capacity is available with no penalty. The changes would be 'win-win' for both customers and Western Power.

1368. Although the ERA considered Mr Schubert's submission had merit and could lead to more efficient outcomes, it is for Western Power to determine the structure of its tariffs within the requirements of the Access Code.

1369. However, under the Access Code, reference tariffs are required to recover the forward-looking efficient costs of providing reference services and charges paid by different users of the reference service should only differ to the extent necessary to reflect differences in the average cost of service provision to the users. In the draft decision, the ERA stated concern the ENUC is in the nature of a penalty rather than a charge to recover forward-looking efficient costs.

1370. The ERA required Western Power to demonstrate that the charge was based on the forward-looking efficient costs from a user exceeding its contracted capacity and that the factors applied for different geographical areas were consistent with the Access Code requirement that charges paid by different users of the reference service only differ to the extent necessary to reflect differences in the average cost of service provision.

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[213] Mr Noel Schubert, *Proposed Revisions to the Price Waterhouse Coopers access arrangement- AA4, 17 December 2017*, p. 7.

1371. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

1372. In its revised proposal, Western Power states it has accepted draft decision required amendment 21. It has provided the following information:[214]

> 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.
>
> 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.
>
> 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.
>
> 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.
>
> **Charges are applied based on constraint**
>
> 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.*
>
> 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.
>
> **Charge structure aligns with Access Code objective, pricing requirements and preserves network safety/reliability**
>
> 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.
>
> 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

[214] Western Power Revised AA4 Proposal Response to the ERA's draft decision 14 June 2018, pp. 151-153.

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.

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;*

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.

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.

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.

Having regard to the above, we submit that the proposed excess network usage charges accord with the Access Code.

1373. WAMEU's submission on the draft decision raises concerns about the proposed increases to the excess network usage charges:[215]

> WAMEU is very concerned that WP is proposing to increase penalties (Excess Network Usage Charge - ENUC) on users of assets which are highly loaded. This is contrary to the requirement that pricing should be cost reflective and not distortionary. WAMEU sees that the ERA is not inclined to change the WP approach to implementing penalties for exceeding contract demands and seems to be supportive of increasing these penalties – WAMEU considers the ERA is in error on this issue and should seek to limit distortionary pricing, especially where there are few options available to end users to manage the increases in costs.
>
> WAMEU considers there are other more appropriate tools available to WP to ensure that the assets do not get overloaded and that each end user pays for the capacity they actually use.

[215] WAMEU, Response to the ERA Draft Decision, May 2018, p. 6.

> WAMEU is very concerned that the application of increased penalties will result in increased revenue for WP which will then be passed back to other consumers through application of the revenue cap. This will result in a transfer of wealth to consumers on less highly utilised assets without achieving any definite benefit to consumers as is required by the National Electricity Objective.

1374. As set out in the draft decision, under the Access Code, reference tariffs are required to recover the forward-looking efficient costs of providing reference services and charges paid by different users of the reference service should only differ to the extent necessary to reflect differences in the average cost of service provision to the users. The ERA was concerned the ENUC is in the nature of a penalty rather than a charge to recover forward-looking efficient costs.

1375. The ERA required Western Power to demonstrate that the charge was based on the forward-looking efficient costs from a user exceeding its contracted capacity and that the factors applied for different geographical areas were consistent with the Access Code requirement that charges paid by different users of the reference service only differ to the extent necessary to reflect differences in the average cost of service provision.

1376. Western Power's response does not include any specific information to demonstrate that the ENUC is based on actual costs that might be incurred if a user exceeded its contracted capacity. The ERA does not consider Western Power has provided information to demonstrate that the proposed charges are based on the forward-looking efficient costs from a user exceeding its contracted capacity. Such evidence will be required before the ERA can approve the proposed ENUC.

Required Amendment 26

Western Power must include in the price list information specific cost information to demonstrate the level of the proposed Excess Network Usage Charges is based on the forward-looking efficient costs from a user exceeding its contracted capacity and that the factors applied for different geographical areas are consistent with the Access Code requirement that charges paid by different users of the reference service only differ to the extent necessary to reflect differences in the average cost of service provision.

Distribution Connected Generators B1 RT11

1377. A submission on the draft decision from Moore River Company submits there is an inequity in Western Power's tariff for distribution connected generators (RT11) which has resulted in its project to develop a solar farm 36 km north of Yanchep not being viable.

1378. The Moore River Company submits the RT11 tariff discriminates against renewable generators because:

- It is not cost reflective - Moore River offered to pay for a dedicated feeder line to the substation but was advised the tariff would not reduce as a result.
- It includes inappropriate costs – the forward-looking efficient costs to connect a renewable generator north of Perth should not include the full sunk cost of transmission lines south of Perth to service coal-fired generators.

- It unfairly penalises renewable energy generators – renewable energy projects offer sustainable and low marginal cost energy but generally need more land than conventional generators. The locational component in the current tariff incentivises generators to connect close to substations.

1379. Access seekers should be able to obtain the element of service they are seeking. If Moore River proposed building its own feeder line rather than using shared assets, it would be expected the network charge would reduce. However, if the feeder line is a connection asset, then it would not result in a reduction in network tariffs as they recover costs of the shared network.

1380. The other concerns Moore River raises regarding discrimination do not appear valid. Network tariffs should be cost reflective and between stand alone and incremental costs. If more distant connections have higher network costs, then it is appropriate for that to be reflected in tariffs, regardless of the type of generation connecting to the network.

Streetlight tariffs

1381. Western Power stated it based its current AA4 proposal for streetlights on the existing practice of generally installing like for like lights on failure. However, Western Power noted there are two factors likely to change this approach:

- Significant improvements in Light-Emitting Diode (LED) technology and affordability mean that it is likely that Western Power will commence replacing failed lights with LEDs. At the time of Western Power's submission, the tender evaluation process was nearly complete. Following which a decision was to be made on a new replacement strategy.
- The Australian Government is currently considering ratifying the Minimata convention[216] on mercury. This could have significant effects on the range of streetlights Western Power can offer.

1382. Western Power noted it was working with Local Government associations to better understand the transition approach that was to be taken. It noted it is too early to assess what will need to change in its access arrangement proposal.

1383. The ERA expected an updated proposal from Western Power following the draft decision. It planned to consider the updated proposal and the matters raised by WALGA in its submission for the final decision.

1384. In Western Power's revised proposal, the updated 2018/19 Price List Information states:

> Western Power is currently evaluating its luminaire replacement strategy. Our preferred position is light emitting diode (LED) streetlight replacements as the default for failed luminaries. In the event of a lamp failure, Western Power will continue to replace the lamp with a traditional lamp equivalent.
>
> Western Power will also offer customers LED equivalent option for all current streetlight types for State Underground Power Program (SUPP) and new subdivision applications.

[216] The Minamata Convention on Mercury is a multilateral environmental agreement that addresses the adverse effects of mercury through practical actions to protect human health and the environment from anthropogenic emissions and releases of mercury and mercury compounds.

> We do not expect there to be a significant variation in forecast costs as the take-up of LEDs as a proportion of the entire streetlight population will not be material during the AA4 period. LED luminaires installed during the AA4 period are not expected to have a materially different maintenance requirement, therefore no change to the streetlight opex allowance has been included in this revised AA4 proposal.

1385. Western Power has included a list of the new LED streetlight models that will be available during AA4 and information mapping them against current luminaire types in the 2018/19 Price List Information.

1386. As set out in Reference and Non-Reference Services, Western Power is required to add new street lighting services based on the services described in WALGA's submission. These include:

- A clearer basis of services, more robustly defining the street lighting services that Western Power provides including light levels, spillage and technology.
- An LED replacement service.
- Different ownership models.
- A new metering type based on metering-grade information technology within smart street lighting controllers and similar devices.

1387. The Price List Information and Price List will need to be updated to incorporate these new services. Streetlight tariffs will also need to be amended to reflect the ERA's final decision on target revenue.

Required Amendment 27

Western Power must amend the Price List and Price List Information to include the required new reference services.

Demand and Customer numbers

1388. Western Power has amended the demand and customer numbers in its revised Price List Information compared with its initial proposal. No information was provided in the submission to support these changes. Western Power has advised that it has refreshed its demand and customer numbers for the 2018/19 year.[217]

1389. The ERA has not had an opportunity to review the refreshed forecast and will be seeking further information on this from Western Power prior to the further final decision. The ERA notes the revised forecast volumes are slightly higher than those used in the initial Price List Information. This contrasts with the latest revenue forecast for 2017/18, which Western Power advises has reduced slightly from the forecast included in its initial proposal. The ERA will be reviewing both of these matters prior to the further final decision.

217 Email response to ERA077 query dated 12 September 2018.

SERVICE STANDARD BENCHMARKS

Access Code requirements

1390. Service standards are defined in section 1.3 of the Access Code to mean either or both of the technical standard, and reliability, of delivered electricity.

1391. Section 5.1(c) requires an access arrangement to include service standard benchmarks for each reference service, as specified under section 5.6.

1392. Section 5.6 of the Access Code requires service standard benchmarks to be:

   (a) reasonable; and

   (b) sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

Current access arrangement

Service standard benchmarks and performance during the AA3 period

1393. The current access arrangement includes service standard benchmarks for the distribution, transmission and street lighting reference service categories. Table 173, below, lists the reference service categories, service standard benchmarks and performance against benchmarks on the Western Power networks in the third access arrangement period.

1394. Western Power achieved the benchmark level of service performance for all performance measures in each year, except in three instances (Table 173, below):

- SAIFI Rural long in 2012/13, due to lightning strikes and other unknown causes.[218]
- SAIFI Rural long in 2013/14, due to pole top fires, fauna interference and localised weather events.[219]
- Average outage duration in 2015/16, due to transformer failures and cable failures.[220]

[218] Western Power, Service Standard Performance Report, Year ending 30 June 2013, 23 September 2013, pp. 23 and 30.

[219] Western Power, Service Standard Performance Report, Year ending 30 June 2014, September 2014, pp. 22 and 28.

[220] Western Power, Service Standard Performance Report, Year ending 30 June 2016, September 2016, p. 22.

Table 173 Western Power service standard benchmarks and actual performance during the AA3 period, from 2012/13 to 2016/17 (sub-benchmark performance is shown in red)

Performance measure	Service Standard Benchmark	2012/13	2013/14	2014/15	2015/16	2016/17
Distribution reliability performance measures						
System average interruption duration index (minutes)						
CBD	39.9	7.6	18.3	26.2	22.6	13.8
Urban	183.0	102.7	107.4	103	91.3	104.4
Rural short	227.8	181.4	171.2	182.6	168.4	175.6
Rural long	724.8	685.4	673.8	677.5	582.6	626.2
System average interruption frequency index (interruptions)						
CBD	0.26	0.03	0.20	0.17	0.1	0.11
Urban	2.12	1.16	1.13	1.09	0.91	1.02
Rural short	2.61	2.17	1.83	1.98	1.75	1.76
Rural long	4.51	4.91	4.98	4.41	3.99	3.95
Calls centre performance (%)	77.50	90.60	92.80	93.70	91.40	91.80
Transmission reliability performance measures						
Circuit availability (%)	97.70	98.37	98.04	98.53	98.66	98.90
System minutes interrupted (minutes)						
Meshed networks	12.5	4.5	4.8	6.6	6.8	8.2
Radial networks	5	1.2	3.7	1.6	0.5	0.7
Loss of supply event frequency (interruptions)						
>0.1 and ≤1.0 system mins.	33	11	17	24	15	16
>1.0 system minutes	4	1	1	0	1	2
Average outage duration (minutes)	886	866	795	720	1265	653
Street lighting repair times (days)						
Metropolitan area	5	1.23	1.14	1.26	1.55	2.47
Regional area	9	2.01	1.07	1.18	0.89	4.59

Western Power's initial proposal

1395. Western Power proposed amendments to the service standard benchmarks during the fourth access arrangement period, including:

- removing the system minutes interrupted measures as service standard benchmarks for the radial and meshed transmission networks

- clarifying the definition of the loss of supply event frequency measure for events greater than 0.1 system minutes
- using five years of data for all measures, rather than three years for SAIDI and SAIFI as had been applied in the third access arrangement period
- using daily unplanned SAIDI (after permitted exclusions), rather than daily SAIDI, to calculate the major event day threshold
- applying a Box-Cox transformation to daily unplanned SAIDI date to calculate the major event day threshold, rather than a logarithmic transformation
- setting benchmarks using a model averaging method, rather than a single model of best fit
- setting benchmarks at the 99th percentile (or 1st percentile for call centre performance and circuit availability), rather than the 97.5th (or 2.5th) percentile
- maintaining the service standard benchmarks set for the third access arrangement period in the 2017/18 financial year

Submissions on Western Power's initial proposal

1396. Submissions referring to proposed amendments to the service standard benchmarks during the fourth access arrangement period were received from:

- Western Australia Council of Social Service (WACOSS).
- Mr Noel Schubert.
- Mr Stephen Davidson.
- Western Australian Local Government Association (WALGA).

1397. WACOSS observed that Western Power had significantly outperformed service standard benchmarks and targets in the third access arrangement period and, noting that service standards are a critical driver of costs, questioned whether an appropriate balance had been struck between service quality and price.[221]

1398. Mr Schubert submitted that edge-of-grid towns and communities in the long rural feeder category experienced extended or frequent outages that were not reflected in aggregate indexes reported by Western Power due to the low customer numbers.[222]

1399. Mr Schubert also requested the introduction of a service standard benchmark to record momentary interruptions, such as Momentary Average Interruption Frequency Index (MAIFI), noting that Western Power had been reporting this information throughout the third access arrangement period.

1400. Mr Davidson made the following submissions on service standard benchmarks:

[221] Western Australian Council of Social Services, AA4 Access Arrangement Submission 2017, 11 December 2017, pp. 10-11.

[222] Mr Noel Schubert, Submission re: Proposed Revisions to the Western Power Network Access Arrangement – AA4, 11 December 2017, pp. 13-14.

- Mr Davidson supported the inclusion of interruptions less of than one minute in service standard benchmarks.[223]

- Mr Davidson objected to the removal of the system minutes interrupted services standard benchmarks and clarification of the loss of supply event frequency measures on the transmission networks, also proposing an amended formula for determining system minutes interrupted.

- Mr Davidson questioned the benchmark levels proposed for the fourth access arrangement period, specifically on the rural long feeder.

- Mr Davidson recommended disallowing many of the exclusions currently permitted for the SAIDI and SAIFI distribution reliability measures, circuit availability and average outage duration service standard benchmarks.

1401. WALGA proposed the introduction of a Public Lighting Code and a contestable maintenance model to enable greater capacity for local councils to manage street lighting networks.[224] These proposals were considered by the ERA to be outside the scope of the access arrangement decision.

Draft Decision

1402. The ERA considered the following proposed amendments and submissions in accordance with the requirements of the Access Code:

- Discontinuing the system minutes interrupted performance measures as service standard benchmarks for the radial and meshed transmission networks.
- Clarifying the definition of the loss of supply event frequency measure for events greater than 0.1 system minutes.
- Using daily unplanned SAIDI (after permitted exclusions), rather than daily SAIDI, to calculate the major event day threshold.
- Applying a Box-Cox transformation to daily unplanned SAIDI date to calculate the major event day threshold, rather than a logarithmic transformation.
- Using five years of data for all measures, rather than three years for SAIDI and SAIFI as had been applied in the third access arrangement period.
- Setting benchmarks using a model averaging method, rather than a single model of best fit.
- Setting benchmarks at the 99th percentile (or 1st percentile for call centre performance and circuit availability), rather than the 97.5th (or 2.5th) percentile.
- Maintaining the service standard benchmarks for the third access arrangement period in the 2017/18 financial year.
- Implementing a service standard benchmark for momentary interruptions.
- Permitted exclusions.

[223] Mr Stephen Davidson, Submission TWO on Proposed Revisions to the Western Power Network Access Arrangement, 11 December 2017, p. 3.

[224] WALGA, Western Power Proposed Access Arrangement 2017-2022, Submission to the Economic Regulation Authority, December 2017, p. 18.

Removal of the system minutes interrupted performance measures

1403. The ERA did not approve Western Power's proposed amendment to remove the disaggregated system minutes interrupted performance measures as service standard benchmarks during the fourth access arrangement period.

1404. The ERA considered:

- Radial feeders were critical components of the transmission network which, unlike meshed networks, do not have redundancy.
- Sections 5.1(c) and 5.6 of the Access Code require an access arrangement to include service standard benchmarks for each reference service and those benchmarks to 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.
- Western Power did not propose an alternative service standard benchmark 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.

1405. Western Power was required to reinstate the system minutes interrupted performance measure, disaggregated for radial and meshed networks, as service standard benchmarks for the fourth access arrangement period:

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 revised proposal

1406. Western Power accepted the required amendment, but maintained its position that the system minutes interrupted performance measure is statistically unsound, being highly volatile and difficult to manage efficiently:

> 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.[225]

1407. Western Power also proposed step-change adjustments to service standard benchmarks to reflect the effect of high impact, low probability events, and changes to the operation of a system protection modification.

Further submissions

1408. No further submissions were received referencing the required amendment to reinstate the disaggregated system minutes interrupted performance measures as service standard benchmark in the fourth access arrangement period.

[225] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 155, para. 895.

Consideration of the ERA

1409. Western Power's proposal to remove the system minutes interrupted performance measure was not approved in the draft decision because the ERA considered:

- The performance measure provided important information to customers and applicants on the radial transmission networks.
- Western Power had not proposed an alternative performance measure that was compliant with the requirements of the Access Code.
- Western Power had not demonstrated that customers on the radial transmission network did not value the system interrupted performance measure.

1410. In its revised proposal, Western Power reiterated its objections to the system minutes interrupted performance measures on the following grounds:

- The Technical Rules, which require N-0 design compliance on the radial transmission networks, and the significant investment required to improve reliability on those networks that would not meet the requirements of the New Facilities Investment Test.[226]
- Evidence that new customers were unwilling to incur the costs of unconstrained access on the radial transmission networks.[227]
- The nature of the measure, based on the size of the lost load, being discriminatory towards larger customers and having no relevance to the customers' experience or assessment of reliability.

1411. Western Power also proposed to adjust the system minutes interrupted service standard benchmarks for the effect of high impact, low probability events, and the new system security protection scheme in the Eastern Goldfields (Table 174, below).

[226] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 155, para. 901-2.

[227] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 155, para. 903.

Table 174 Proposed step-change adjustments to the system minutes interrupted service standard benchmarks (SSB) for the years 2018/19 to 2021/22 due to high impact, low probability (HILP) events and system protection modification (SPM)

Performance measure	SSB unadjusted	HILP adjustment	SPM adjustment	SSB proposed
System minutes interrupted				
- Radial	4.6	4.8	-	9.4
- Meshed	11.7	-	5.7	17.3

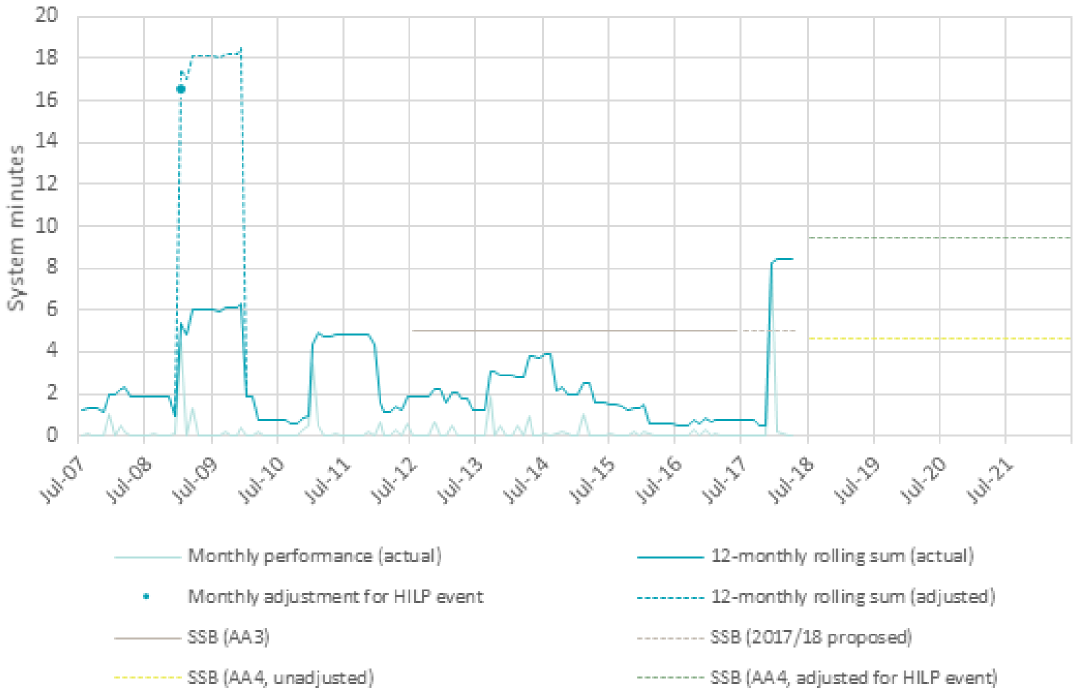
1412. Western Power explained the proposed adjustments to the service standard benchmarks for system minutes interrupted (radial network) performance measure for high impact, low probability events as follows:

- Radial transmission networks are particularly susceptible to high impact, low probability events, particularly in regional areas and on radial feeders having no redundancy.
- Performance during the fourth access arrangement period had been relatively good in comparison with the third access arrangement period. The effect of this performance was to systematically underestimate the risk of a low probability, high impact event in the fourth access arrangement period.[228]
- Western Power experienced a significant event on the technically compliant (N-0) 132 kV line between West Kalgoorlie Terminal and Black Flag that caused the system minutes interrupted (radial) performance to increase from 0.4 system minutes in November 2017 to 8.3 system minutes in December 2017.
- Western Power considered the cost of alleviating the impact of these events, estimated to be $30 million required in several areas, to be neither prudent nor efficient.
- Western Power proposed a step-change adjustment by modelling and excluding the effect of a one-in-ten year event.

1413. Western Power proposed an adjustment to the service standard benchmark for system minutes interrupted radial networks for the fourth access arrangement period, from 4.6 system minutes to 9.4 system minutes, shown in Figure 12, below.

[228] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 163, para. 949.

Figure 12 Historical performance of the system minutes interrupted radial network performance measure, inlcuding proposed adjustments for high impact, low probability (HILP) events, and service standard benchmarks for the AA4 period



1414. Western Power also proposed a step-change adjustment to the system minutes interrupted (meshed network) service standard benchmark to reflect the system security protection scheme in the Eastern Goldfields. Western Power explained:

- Any outages on the 220 kV transmission line between Muja, through Merredin and Colgar terminals would result in thermal overloading on the Merredin to Northam 132 kV line and voltage and transient stability issues on the Eastern Goldfields networks.

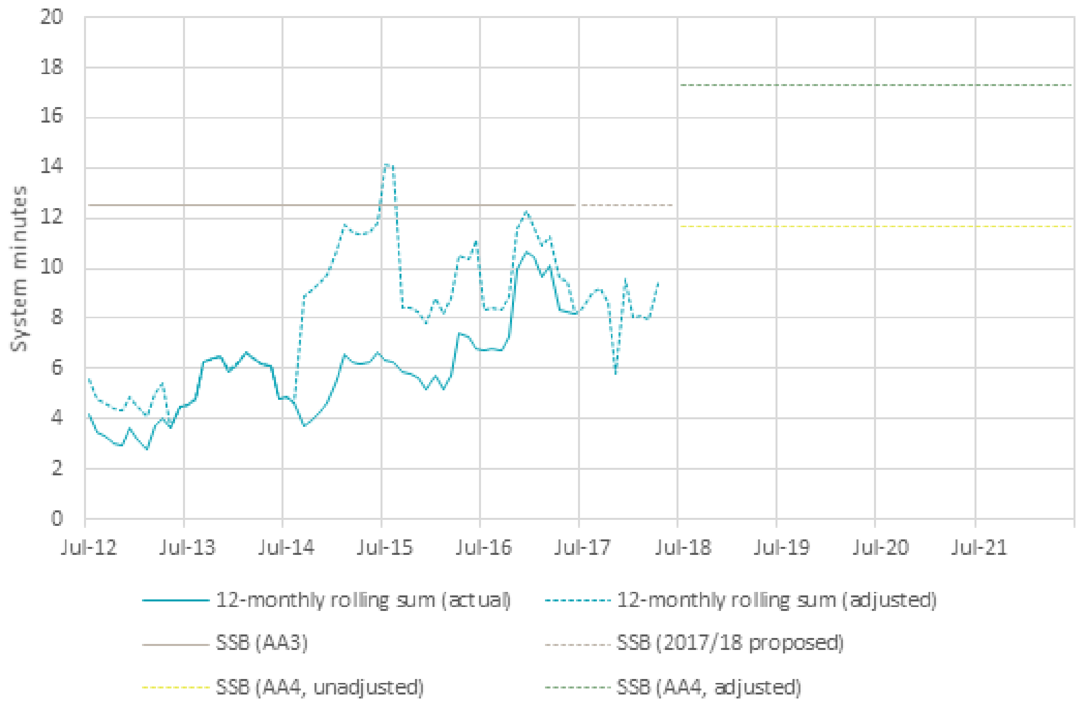
- Modifications were implemented in February 2016 that resulted in all load from the Muja Terminal being disconnected following a trip in the Muja Terminal to Merredin Terminal line.

- Due to the size of load and time to restore the 220 kV network following an interruption, all associated events will be greater than one system minute.

- Western Power proposed to adjust the service standard benchmark for the fourth access arrangement period by backcasting performance data from the third access arrangement period assuming the protection scheme was in place for the entire period.

1415. The effect of the proposed adjustment of the service standard benchmark for system minutes interrupted performance measure on meshed networks, from 11.7 to 17.3 system minutes, is shown in Figure 13, below.

Figure 13 Historical performance of the system minutes interrupted meshed network performance measure, including adjustments for the system security protection modification, and proposed service standard benchmarks for the AA4 period



1416. The ERA has considered the following options for addressing the volatility of the system minutes interrupted performance measures for the purpose of setting a service standard benchmark:

- The step-change adjustments to system minutes interrupted service standard benchmarks proposed by Western Power.
- The continuation of the system minutes interrupted performance measures as service standard benchmarks.

Step-change adjustments proposed by Western Power

1417. The ERA engaged a technical consultant to provide advice on the adjustments proposed by Western Power to the service standard benchmarks for the system minutes interrupted performance measures.

1418. The consultant considered the adjustment to the system minutes interrupted (radial networks) service standard benchmark to account for the effect of high impact, low probability events to be "so much higher than the service level that the network would normally be expected to deliver that it serves no useful purpose as a benchmark."[229]

1419. The consultant recommended that, if the system minutes interrupted measure was to be retained as a service standard benchmark, high impact, low probability events in excess of a specified threshold should be excluded from the performance data in

[229] Geoff Brown and Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018.

a similar manner as major event days are excluded from distribution performance measures.

1420. On the proposed adjustment to the system minutes interrupted (meshed networks) service standard benchmark to account for the system protection scheme, the technical consultant also concluded:

- Western Power's decision to modify the special protection scheme on the 220 kV lines between Muja and Merredin, which would result in an increased number of interruptions to the Eastern Goldfields, is justified.

- The deterioration in the system minutes interrupted meshed networks performance measure in 2015/16 was consistent with the implementation of the system protection scheme in February 2016.

- The basis for adjusting the system minutes interrupted meshed networks performance measure is probably not unreasonable, but some doubt remains about the manner in which the adjustments have been calculated.

1421. On the proposed adjustments to system minutes interrupted performance measures, the consultant expressed concern that the actual system minutes interrupted performance measure was dependent upon the time of interruption and that probability that the interruption occurred at the time of peak demand is very low.

1422. The adjustments proposed by Western Power appeared to assume that all interruptions occurred at times of peak demand, and continued without variation for the duration of the interruption. An accurate estimation of the effect of an interruption should take account of the demand at the start of the interruption and the load profile for the duration of the interruption. It was not apparent that Western Power had factored these considerations into its proposed adjustments.

1423. Given the subjectivity of the step-change adjustments proposed by Western Power, the ERA considered whether the system minutes interrupted performance measures should be retained as service standard benchmarks.

Continuation of the system minutes interrupted performance measures as service standard benchmarks

1424. The ERA's technical consultant advised that, although the system minutes interrupted performance measures provide information highly relevant to users on the transmission networks, the measures suffer from two significant limitations. Those limitations are that energy not served cannot be measured, and the duration measure is technically unbounded:

- Energy not served cannot be measured. While the demand at the time a load is interrupted and the demand at the time the load is restored are both known, the variations in demand over the period of the interruption are not known. All transmission loads are metered half-hourly and WP estimates the amount of energy not served on the basis of an analysis of historic demand curves for the loads in question. At best this is an informed estimate, the accuracy of which is likely to reduce with increasing interruption duration.

- Unlike service levels based on frequency, it is an unbounded measure. When an interruption occurs, it will count as a single interruption irrespective of duration. However, SMI will continue to accumulate until supply is restored. This means

> that measured SMI could be substantially higher than the level the network would normally be expected to deliver following a HILP event.[230]

1425. The technical consultant concluded that, although the parameter is very relevant to network users, the measures are subjective estimates. The consultant expressed reservations with the continuation of the performance measure as a service standard benchmark due to the subjectivity and financial implications of compliance with the gain share mechanism or service standard adjustment mechanism. Additional concerns listed by the consultant included:

   - The distortion of the measure by high impact, low probability events that may be outside Western Power's ability to control.

   - The high number of service standard benchmarks that Western Power is required to achieve in order to qualify for the above-benchmark surplus under the gain share mechanism, and the significant financial implications of non-compliance with any single measure.

   - The Australian Energy Regulator has discontinued the use of the system minutes interrupted performance measure.

1426. The technical consultant recommended that Western Power continue to report its best estimate of performance against the system minutes interrupted performance measures in Service Standard Performance Reports, but that they be discontinued as service standard benchmarks for the purpose of the gain share mechanism or service standard adjustment mechanism:

> It is therefore recommended that the SMI not be used as a SSB or included in either the GSM or SSAM. However, the Authority should require WP to report its best estimate of the actual SMI in its annual Service Standard Reports and to provide a detailed explanation for significant deviations from levels typically recorded for the network. This would include discussion for the causes of any HILP events encountered during the reporting year and the SMI impact of such event.[231]

1427. Western Power cited the Northern Territory as an example of a jurisdiction in which regional reliability is reported only, without a performance target being set.[232]

1428. The ERA does not have authority under the Access Code to require Western Power to report against a performance measure that is not a service standard benchmark, although does have a broad authority to collect and maintain data in connection with cost allocations for the derivation of target revenue (section 14.4).

1429. The ERA also considered whether the implementation or reporting of a disaggregated loss of supply event frequency performance measure for radial and meshed networks would satisfy the requirements of the Access Code, as presented in Table 122 of the draft decision.[233]

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[230] Geoff Brown and Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018.

[231] Geoff Brown and Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018

[232] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 155, fn. 170.

[233] Economic Regulation Authority, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 2 May 2018, p. 212, Table 122.

1430. In a submission to Western Power's initial proposal, Mr Davidson had proposed the implementation of separate measures of loss of supply event frequency for the radial and transmission networks to be consistent with the requirements of the Access Code.[234] The ERA considered the proposal to be consistent with the requirements of the Access Code, subject to the retention of the disaggregated system minutes interrupted performance measures.[235]

1431. In its revised proposal, Western Power stated that it was unable to propose a more accurate, reliable and meaningful measure to replace system minutes interrupted as a performance measure on the radial transmission network. Western Power also considered the disaggregated loss of supply event frequency performance measures for radial and transmission measures could not be used to derive a workable service standard benchmark:

> 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 been unworkable and would have required Western Power to invest heavily in several areas of the radial network.[236]

1432. The ERA's technical consultant also considered the proposal to implement disaggregated loss of supply event frequency performance measures for the radial and meshed networks to have some benefit. It was concerned, however, that the system protection measure on the 220kV circuit between Muja Terminal and Merredin Terminal had created hybrid circuits with both radial and meshed characteristics and that clarification of the classification of these circuits would be required to accurately report a disaggregated performance measure.

1433. In summary, the ERA has considered the following matters and decided that the continuation of the system minutes interrupted measure as a service standard benchmark would not be consistent with the requirements of the Access Code:

- Western Power's initial proposal to discontinue reporting the system minutes interrupted performance measures.
- Reservations expressed by Western Power in the revised proposal.
- The subjectivity of the measure and assumptions used to derive proposed step-change adjustments.
- Technical advice from an independent consultant, advising that the outage data provided valuable information to users on the network and recommending the performance measure continue to be reported, but discontinued as a performance benchmark due to the subjectivity and financial implications of non-compliance.

[234] Mr Stephen Davidson, Submission TWO on Proposed Revisions to the Western Power Network Access Arrangement, 11 December 2017, p. 8.

[235] Economic Regulation Authority, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 2 May 2018, p. 219, para. 970.

[236] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 155, para. 904.

Required Amendment 28

Western Power must discontinue reporting the system minutes interrupted (radial and meshed) performance measures as service standard benchmarks.

Required Amendment 29

Western Power must make clear the classification of 220kV circuits between Muja Terminal and Merredin Terminal, and report disaggregated loss of supply event frequency performance measures for radial and meshed circuits. Western Power is not required to set service standard benchmark for the radial and meshed elements of the loss of supply event frequency performance measures.

Clarification of the loss of supply event frequency definition

1434. Western Power proposed to make clear that the two loss of supply event frequency measures are independent and reflect different types of events by specifying the loss of supply event frequency greater than 0.1 system minutes interrupted relates to events where loss of supply exceeds 0.1 and is equal to or less than 1.0 system minutes interrupted.[237]

1435. The ERA considered Western Power's proposal to clarify the definition of the loss of supply event frequency service standard benchmarks as two discrete performance measures to be reasonable and sufficiently detailed and complete to enable a user or applicant to determine the value of the reference service at the reference tariff.

1436. The ERA approved the proposed amendment to clarify the loss of supply event frequency as two discrete measures, comprising events:

- exceeding 0.1 system minutes interrupted and less than or equal to 1.0 system minutes interrupted; and
- exceeding 1.0 system minutes interrupted.

Western Power's revised proposal

1437. Western Power did not submit a revised proposal to clarify the loss of supply event frequency performance measure.

1438. Western Power did submit a proposal to adjust the service standard benchmark for loss of supply event frequency greater than 1.0 system minutes, from four to six interruptions per year.

[237] Western Power, Access arrangement information, Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 88, para. 297.

Further submissions

1439. Mr Stephen Davidson submitted further comments clarifying the proposal to amend the formula for calculating system minutes using system peak load at the time of the interruption, rather than peak load during the preceding year.

Considerations of the ERA

1440. The ERA has considered the following matters to determine the consistency of the loss of supply event frequency service standard benchmarks with the requirements of the Access Code:

- Step-change adjustments to the service standard benchmark proposed by Western Power.
- Modified calculation of system minutes proposed by Mr Davidson.

Step-change adjustments to service standard benchmarks

1441. Western Power proposed to increase the service standard benchmark for loss of supply event frequency from four to six interruptions per year due to the establishment of a new system security protection scheme in the Eastern Goldfields in February 2016.

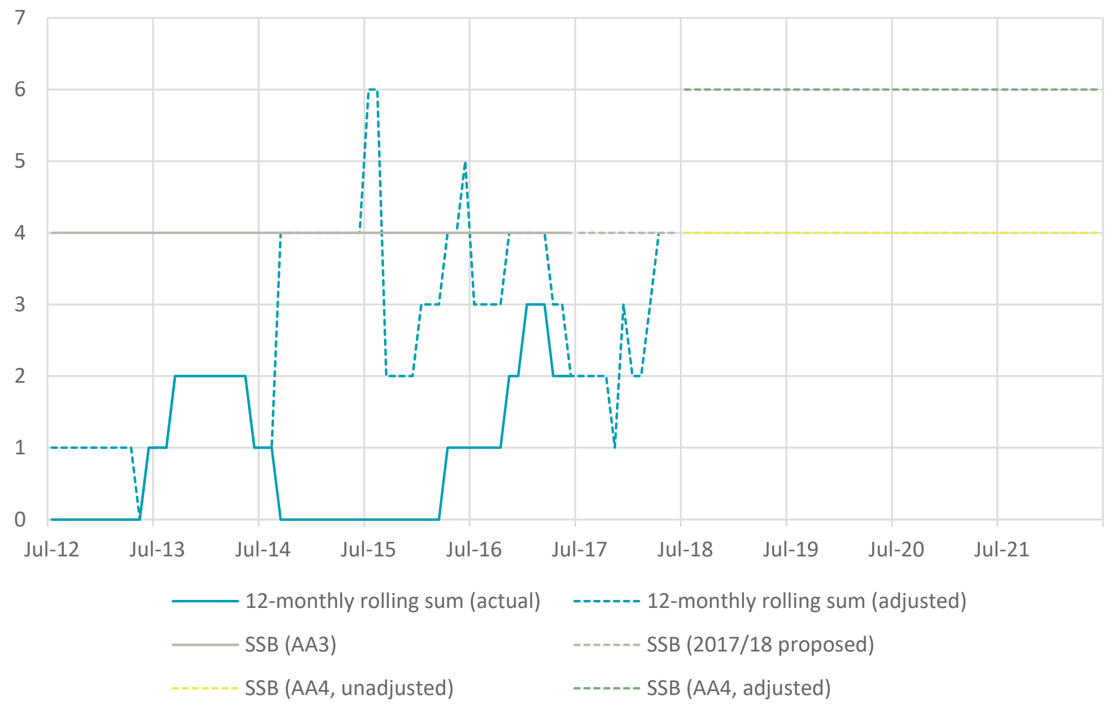
1442. Western Power explained that, had the system protection scheme been in place for the duration of the third access arrangement period, an additional eight interruptions exceeding one system minute would have occurred during the period, because:

- Supply restoration to the Eastern Goldfields, with a load of approximately 100MW, takes on average approximately 55 minutes, resulting in an average outage event of 1.4 system minutes.
- The length of line that will result in a loss of supply to the Eastern Goldfields increased from 326 kilometres (from Merredin to the West Kalgoorlie Terminal) to 655 kilometres (from Muja to the West Kalgoorlie Terminal) such that a lightning strike on this part of the network will increase the number of outages in excess of 1.0 minutes by an average of 2.6 events per year.

1443. Western Power also referred to actual performance during the 2017/18 year (to April 2018), in which the loss of supply event frequency measure (greater than 1.0 minutes) recorded four events, which compares with an average of one event in the third access arrangement period, and two events recorded in 2016/17.

1444. Western Power's actual performance, adjusted performance and proposed step-changes to the loss of supply event frequency service standard benchmarks are shown in Figure 14, below.

Figure 14: Historical performance of the loss of supply event frequence (>1.0 system minutes) performance measure, including adjustments for the system security protection modification, and proposed service standard benchmarks for the AA4 period



1445. The ERA engaged a technical consultant to assess the reasonableness of Western Power's proposal to increase the service standard benchmark for the loss of supply event frequency (greater than 1.0 system minutes) performance measure. The ERA's technical consultant observed:

- The overloading of the Northam-Merredin Terminal following a fault on any of the 220kV lines between Muja and Merredin Terminals is plausible.
- The deterioration in performance after 2015/16 is consistent with the introduction of a modified system protection scheme in February 2016.
- The actual system minutes interrupted will depend on the time of interruption and it is not clear that Western Power has factored this into its calculation.
- With the new system protection measures in place, the three 220kV circuits between Muja and Merredin have both radial and meshed characteristics, although supply to the Eastern Goldfields is still classified as radial. The loss of supply event frequency performance measures however are not disaggregated for meshed and radial networks.

1446. The ERA's technical consultant concluded, given the four interruptions in 2017/18 with an outage greater than 1.0 system minutes, Western Power's proposal to increase the service standard benchmark for the loss of supply event frequency (greater than 1.0 system minutes), appeared reasonable.[238]

1447. Having regard to Western Power's proposal to adjust the loss of supply event frequency (>1.0 system minutes) service standard benchmark from four to six events, and advice received from the technical consultant, the ERA considers the proposed adjustment to be reasonable.

Revised formula for calculating system minutes interrupted

1448. Mr Stephen Davidson submitted further clarification of a proposed modification to the calculation of system minutes interrupted.

1449. Mr Davidson also expressed concern that the access arrangement review process lacked transparency and fairness, suggesting a Chartered Professional Engineer should be obligated to ascertain the technical content of Western Power's proposal.

1450. The current formula defined in the access arrangement applies a "load integration method" to determine system minutes interrupted as a factor of the system peak load:

$$\text{System minutes interrupted} = \frac{\sum(\text{MW unsupplied} * 60)}{\text{System peak MW}}$$

Where "MW unsupplied" is the energy not supplied (in megawatts), while "System peak MW" is the maximum peak demand on the South West Interconnected System for the previous financial year.

1451. Mr Davidson proposed a formula that utilises the system peak load at the time of the interruption on the basis that the interruption will have a greater effect if it occurs during low or medium loads, rather than at peak loads:

$$\text{System minutes interrupted} = \frac{\sum(\text{MW unsupplied} * 60)}{\text{System peak load in MW at the time of interruption}}$$

1452. Mr Davidson submitted that the outage should be considered from a customer perspective :

> The rationale is that one should observe the event from the customer's perspective, and at the instant in time when that customer lost its electricity supply. The principal measure should be the percentage loss of the electricity supply experienced by the customer. If the supply is completely interrupted, then it should be measured and reported as 100% (loss of supply).
>
> Since, we do not have individual MW measurements across the SWIS (Individual Load in MW at the Time of Interruption), the best we can do is to use the SWIS system load as the denominator, and as the proxy for the relative severity of the loss-of-load event (System Load in MW at the Time of Interruption).[239]

[238] Geoff Brown and Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018.

[239] Mr Stephen Davidson, Attachment 1: Submission TWO (General Comments & Comments on Issue 13), Draft Decision on Proposed Revisions to the Western Power Network Access Arrangement – AA4, 14 June 2018, p. 2.

1453. Mr Davidson also explained that, since the peak load in each trading interval in the Wholesale Electricity Market is known, the proposed formula gives a more accurate measure of the size of lost load at the time of the interruption.

1454. Mr Davidson also stated that the proposed denominator, utilising system load in MW at the (trading interval) time of interruption, permits the immediate calculation of the performance indicator and "captures more unique features" of the South West Interconnected System:

> … hence, it is a more sophisticated / accurate measure (than that proposed by Western Power). This additional information adds to granularity and richness of the calculated performance indicator(s), that allows for more informed decision making, and ultimately better promotes 'competition in markets upstream and downstream of the networks'.[240]

1455. Western Power has stated in response to the formula proposed by Mr Davidson that the existing approach provides a consistent and generic reference that enables aggregation of the impacts in a financial year.[241]

1456. Western Power also stated in its revised proposal, in reference to the system minutes interrupted performance measure, that the size of the load at the time of the interruption is not relevant to the customers' experience or assessment of reliability:

> 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.[242]

1457. The ERA also engaged a technical consultant to provide advice on the consistency of the formula proposed by Mr Davidson with the Access Code. The technical consultant advised that the standard definition of a system minute is the energy delivered by a transmission system operating at peak demand for a period of one minute. The system load at the time of an interruption is not relevant to a particular customer interruption, and the "System Peak MW" denominator enables normalisation of an interruption event across the network.[243]

1458. By example, an interruption in a customer load of 100MW for 2 hours would result in unserved energy of 200 MWh. If the interruption occurred at a time of peak load on the system of 4000MW, the resulting interruption would be measured as 3 system minutes. If the same interruption occurred at a time when system load was 2000MW, the resulting interruption would be recorded as 6 system minutes. The resulting interruption is the same in both cases and is not affected by the level of demand on the network at the time of the interruption.

1459. The technical consultant did recommend that the definition of "System Peak MW" be clarified to explicitly exclude load supplied to non-reference customers.

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[240] Mr Stephen Davidson, Attachment 1: Submission TWO (General Comments & Comments on Issue 13), Draft Decision on Proposed Revisions to the Western Power Network Access Arrangement – AA4, 14 June 2018, p. 3.

[241] Western Power, Response to ERA enquiry, ERA058 – Service standard benchmarks, 7 August 2018

[242] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 156, para. 906.

[243] Geoff Brown and Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018.

1460. The ERA considers the revised formula proposed by Mr Davidson to be inconsistent with the requirements of the Access Code.

1461. The ERA also considers the clarification of the system minutes interrupted formula to exclude load supplied to non-reference customers to be reasonable, and consistent with existing practice and the requirements of the Access Code.

1462. In response to Mr Davidson's concern with the fairness and transparency of the access arrangement review process, Western Power advised that its submission and associated materials have been prepared "in good faith and with due care and expertise, including those of qualified engineers."[244]

1463. The ERA considers public confidence in the access arrangement review process would be enhanced with a requirement that technical content and assumptions underlying Western Power's proposal be certified by a professionally qualified expert. The ERA will give consideration to the requirement that technical content and assumptions underlying Western Power's access arrangement information be certified in the access arrangement guidelines.

Required Amendment 30

Western Power must amend the definition of "System Peak MW" within the loss of supply event frequency formula as follows:

"System Peak MW" is the maximum peak demand recorded on the South West Interconnected System for the previous financial year, excluding the coincident demand of customers directly connected to the transmission system and receiving a non-reference service.

Events considered in defining major event days

1464. Western Power proposed to remove planned interruptions from daily SAIDI data for the purpose of calculating the major event day threshold.

1465. The proposal was consistent with the currently permitted exclusions for reporting annual reliability performance and the service target performance incentive scheme administered by the Australian Energy Regulator.

1466. The ERA considered the use of daily unplanned SAIDI, derived after interruptions permitted to be excluded for the purposes of measuring distribution reliability, to be reasonable and sufficiently detailed and complete to enable a user or applicant to determine the value of the reference service at the reference tariff.

1467. The ERA approved the proposed amendment to the access arrangement specifying that daily unplanned SAIDI, calculated over the five immediately preceding financial

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[244] Western Power, Response to ERA enquiry, ERA058 – Service standard benchmarks, 7 August 2018.

years after permitted exclusions, be used in calculating the major event day threshold.

Western Power's revised proposal

1468. Western Power did not submit a revised proposal on the events considered in defining major event days.

Further submissions

1469. No further submissions were received that referenced the events considered in defining major event days.

Considerations of the ERA

1470. The ERA maintains the draft decision to approve the exclusion of planned outages from daily SAIDI data for the purpose of calculating the major event day threshold.

Determining the probability of a major event day

1471. Western Power proposed to apply the Box-Cox method of transforming daily unplanned SAIDI data to fit a normal distribution for the purpose of calculating the major event day threshold value.

1472. Subject to transparent reporting of the method applied by Western Power in determining the major event day threshold, the ERA considered the proposal to apply the Box-Cox transformation to daily unplanned SAIDI data to be reasonable and sufficiently detailed and complete to enable a user or applicant to determine the value of the reference service at the reference tariff.

1473. The ERA approved the proposal to apply the Box-Cox transformation to daily unplanned SAIDI data to determine the major event day with the following required amendment:

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.

3) Demonstrate that the resulting data set is normally distributed or that the normality of the data set is improved.

Western Power's revised proposal

1474. Western Power accepted the amendment with a modification clarifying that the required information will be provided in annual service standard performance reports submitted to the ERA in compliance with Chapter 11 of the Access Code.

Further submissions

1475. No further submissions were received that referenced the method for determining the major event day threshold.

Considerations of the ERA

1476. The ERA considers the proposed amendment to be consistent with the draft decision and approves the proposed amendment to clarify that the required information will be provided by Western Power in annual service standard performance reports submitted under Chapter 11 of the Access Code.

Determining the time period for data for setting service standard benchmarks and targets

1477. Western Power proposed to use five years of data corresponding to the third access arrangement period to derive service standard benchmarks and targets for the fourth access arrangement period.

1478. The ERA considered the use of five years of data to determine service standard benchmarks and targets to be reasonable and sufficiently detailed and complete to enable a user or applicant to determine the value of the reference service at the reference tariff

1479. The ERA approved the use of five years of performance data to determine service standard benchmarks and targets for the fourth access arrangement period.

1480. The required amendment (24) referred to the "most recent five-years of performance data."

Western Power's revised proposal

1481. Western Power stated in the revised proposal that it interprets the required amendment to refer to the five-year period corresponding to the third access arrangement period:

> 938. The ERA states Western Power must set SSBs based on the *most recent five years of performance data*.
>
> 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.[245] [emphasis in original]

[245] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 162, para. 939.

Further submissions

1482. No submissions were received that referenced the time period of the data used to determine service standard benchmarks and targets.

Considerations of the ERA

1483. The ERA confirms the intention of the draft decision, that five years of performance data corresponding to the third access arrangement period be used to derive service standard benchmarks and targets for the years 2018/19 to 2021/22.

Averaging the percentile values of probability distributions selected according to nominated threshold criteria

1484. Western Power proposed to set service standard benchmarks by averaging the nominated percentile value from multiple probability distributions fitted to historical performance data. Each probability distribution was selected subject to goodness-of-fit criteria.

1485. The proposed approach differed from the method applied in the third access arrangement period. Service standard benchmarks were derived in the third access arrangement period at the nominated percentile of the single probability distribution of best fit to historical performance data constructed as a 12-month rolling sum of monthly performance values over a three or five year period.

1486. The ERA did not consider the method proposed by Western Power to be reasonable and did not approve the method in the draft decision because:

- The service standard benchmarks derived by Western Power under the multi-model averaging method did not differ significantly from those derived by sampling the single distribution of best fit.
- The process for determining the model selection threshold appeared to be arbitrary and based on the analysis of a single performance measure.
- The number and composition of distributions selected were likely to vary with time, introducing volatility and uncertainty.
- Western Power had not objectively demonstrated the improved robustness of the service standard benchmarks derived under the multi-model approach.

1487. The draft decision required Western Power to derive service standard benchmarks at the nominated percentile of the single probability distribution of best fit:

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 revised proposal

1488. Western Power did not accept the required amendment and maintained its position that service standard benchmarks be derived by averaging percentile values sampled from multiple probability distributions selected subject to nominated threshold criteria.

1489. Western Power referred to its independent expert's report, prepared by Analytics + Data Science, which claimed the multi-model averaging process is desirable if it results in a more accurate, consistent, replicable, and robust statistical model of the physical processes that affect service standards:

> The objective underpinning the distribution fitting process is not to attempt to identify the one single "true" model. Instead, the methodology should accurately model, as far as is practicable, those physical processes that drive SSB/SST variability in a consistent and replicable manner. For this reason the use of 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.[246]

1490. Analytics + Data Science also stated that the method proposed by Western Power was consistent with "state-of-the-art practice in statistical inference":

> Burnham & Anderson (2004) provide a more complete discussion of the conclusions from multiple studies that demonstrate that a multimodel averaging approach is superior to the methodology in which parameter estimates are obtained from only the single "best" model.
>
> Consequently, a+ds considers 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.[247]

Further submissions

1491. No public submissions were received that referenced the component of the required amendment specifying the use of a single probability distribution of best fit to derive service standard benchmarks.

Considerations of the ERA

1492. The ERA engaged an expert consultant, Pink Lake Analytics, to assess Western Power's proposed method of deriving service standard benchmarks. Specifically, Pink Lake Analytics was requested to assess and report on the accuracy, consistency, replicability, and robustness of the proposed method.[248]

1493. Pink Lake Analytics implemented a two-stage Monte Carlo simulation method using daily customer interruption data previously supplied by Western Power. The approach assumed a mixture model estimated from daily customer interruption data on the distribution network as a hypothetical 'true' distribution. The first stage constructs a sampling distribution of annual SAIDI and SAIFI values from which service standard benchmarks at nominated percentiles are derived. The second

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[246] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 4.

[247] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 4.

[248] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018.

stage constructs a 'true' distribution of service standard benchmarks through repeated trials of the first stage. The true distribution of service standard benchmarks was then compared with the sampling distribution of service standard benchmarks generated by the model averaging method proposed by Western Power and parametric distributions fitted to each first stage simulation of annual SAIDI and SAIFI values.[249]

1494. Pink Lake Analytics applied numerical measures of statistical performance to evaluate Western Power's claims of improved accuracy, replicability, consistency and robustness of the proposed service standard benchmarks.[250]

1495. Each of the matters below was considered by the ERA to determine the compliance of the method proposed by Western Power for setting service standard benchmarks with the requirements of the Access Code:

- The accuracy of the service standard benchmarks proposed by Western Power.
- The replicability of the method proposed by Western Power.
- The consistency of the method proposed by Western Power for deriving service standard benchmark over time.
- The statistical robustness of the method proposed by Western Power relative to the method applied in the third access arrangement period.

Accuracy of the service standard benchmarks proposed by Western Power

1496. Western Power stated in its initial proposal that the method of averaging multiple distributions would "ensure a more accurate estimation" of service performance benchmarks as compliance measures:

> 338. We consider the methodology for averaging distributions for AA4 will ensure more accurate estimation of the probability of these compliance measures being met, provide appropriate incentives for Western Power to maintain compliance under the service incentive framework, and ensure the setting of more consistent SSBs over time all else being equal.[251]

1497. The expert report prepared by Analytics + Data Science for the revised proposal also stated that the objective of the distribution fitting process is to accurately model, as far as is practicable, the physical processes affecting service standards (referenced at paragraph 1489, above).

1498. Simple analysis presented in the draft decision demonstrated that percentile estimates derived under the multi-model averaging method proposed by Western

[249] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. iii.

[250] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. iii.

[251] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p.95, para. 338.

Power were not significantly different to those derived from the single distribution of best fit.[252]

1499. Western Power did not challenge this analysis and there were no public submissions critical of this finding.

1500. Pink Lake Analytics also assessed the claims of improved accuracy in the estimated service standard benchmarks proposed by Western Power. The root mean squared error formula was proposed as a measure of out-of-sample accuracy of the model given uncertainty in parameter estimates.[253]

1501. Pink Lake Analytics concluded that the method proposed by Western Power to derive service standard benchmarks did not achieve a more accurate estimate of the service standard benchmark in all scenarios:

> The Proponent's method is marginally more accurate than the single best model and [the Burnham and Anderson Information Theoretic Approach] in only some data scenarios, and marginally less accurate in other scenarios, as measured by the [root mean squared error] estimate of the prediction error.[254]

1502. Having regard to Western Power's proposed method, and the expert report prepared by Pink Lake Analytics, the ERA considers that Western Power's claims of improved accuracy of the proposed method for deriving service standard benchmarks have not been objectively or conclusively demonstrated.

Replicability of the method proposed by Western Power

1503. Western Power's expert report, prepared by Analytics + Data Science, claimed that the proposed method of deriving service standard benchmarks "should accurately model, as far as is practicable, those physical processes that drive SSB/SST variability in a consistent and replicable manner" (paragraph 1489, above).

1504. Pink Lake Analytics assessed the standard error of the estimated service standard benchmarks as a weak measure of replicability of the derived benchmarks from sample to sample. Pink Lake Analytics concluded the preference for one method over another to be data dependent:

> As with prediction error, the standard error estimate of precision (taken as a measure of replicability of estimates with different samples) was only marginally different between model averaging methods, including the single best model. No method dominated, with preference for one model averaging method over another varying with data scenario.[255]

1505. The ERA also considered the question of replicability within the context of section 5.6 of the Access Code, which requires service standard benchmarks to be reasonable and sufficiently detailed and complete to enable a user or applicant to determine the value of the reference service at the reference tariff. Implicit in this requirement is

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[252] Economic Regulation Authority, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 2 May 2018, p. 230, Table 124.

[253] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018.

[254] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 14.

[255] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 15.

that users or applicants may independently derive service standard benchmarks identical to those proposed by Western Power from the same performance data.

1506. In the draft decision, the ERA considered the process for selecting a threshold value from which models are selected or excluded to be arbitrary and based on the analysis of a single performance measure.[256] The rationale provided by Western Power indicated that the threshold value was selected principally to ensure that some, but not all, candidate distributions were selected in the model averaging method:

> A threshold that is too high would result in the all evaluated distributions being considered, departing from the principle that the SSB/SST should be based on the distribution of best fit. A threshold that is too low would result in only the single best distribution being considered, negating the rationale for averaging the 99th percentile values. The one per cent threshold provides a pragmatic trade-off between considering too many and too few candidate distributions.[257]

1507. The nominated threshold value was not selected based on an optimised, objective measure of statistical robustness. A marginal, arbitrary shift in the threshold value in either direction would result in the selection of a single distribution of best fit, or all candidate distributions, rendering the ranking process redundant.

1508. In its revised proposal, Western Power cited the expert report prepared by Analytics + Data Science, which acknowledged the lack of consensus, sensitivity of the model results, and discretionary nature of the choice of threshold:

> A+DS highlights that there is no single threshold value that is used as a common standard, instead the *discretion remains with the analyst*.[258] [emphasis in original]
>
> The lack of consensus does not imply that any particular value is arbitrary, only that some discretion remains with the analyst.
>
> …
>
> Evidently, small changes in the assumed threshold value will impact the final multimodel output.[259]

1509. Analytics + Data Science concluded that, despite the lack of consensus, the discretionary method proposed by Western Power is consistent with best practice approaches:

> All methods depend on the use of a threshold value, for which there is no uniquely agreed value in the peer-reviewed literature.

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[256] Economic Regulation Authority, Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 2 May 2018, p.229, para.1018.

[257] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 95, fn. 82.

[258] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p.158-9, para. 919.

[259] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 6.

> Consequently, 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, noting that alternative but complementary approaches exist.[260]

1510. In contrast, Pink Lake Analytics stated that the evidence supporting Western Power's proposed method of model averaging is weak for the following reasons:

- Western Power's assertions that the proposed method is consistent with best practice cannot be sustained across all data scenarios:

> The overarching conclusion with regard to model averaging is that the Proponent's assertion that their method is best-practice cannot be applied generically across all data scenarios. Indeed, the single best model outperforms the Proponent's method under some data scenarios.[261]

- The equal weighting method proposed by Western Power is not optimal:

> Moreover, applying an unequal weighting (as implemented under the BAITA) will typically be superior to equal weights (as implemented by the Proponent).
>
> …
>
> In BAITA theory, any model with a non-zero Akaike weight may be included in the model averaging under BAITA… If there is uncertainty around these cut-off values then the default position should arguably be to not apply cut-offs. Regardless, it is preferable to weight component models by their Akaike weights, rather than equal weights that the Proponent applies. The strict BAITA has been designed in part to minimise model selection bias, and issues with equal weighting are well known in theory. [262]

- The single example of a threshold value provided by Western Power, corresponding to that recommended in the literature, is coincidental:

> The Proponent provides a positive example of where their 1% threshold coincides with a 0.95 cut-off applied to the Akaike weights w_i. This example is co-incidental… the cumulative Akaike weight is widely distributed relative to the 1% cut-off. As such, providing a single example of confirmation, without objectively testing for examples of non-confirmation, may be categorized as a *'fallacy of the lonely fact'*.[263] [emphasis in original]

1511. A recent paper, cited by Analytics + Data Science, also referred to the disagreement among practitioners of the model averaging method and acknowledged that different approaches may produce different outcomes:

> Model averaging in an AIC framework is still an area that raises some thorny issues concerning both methodology and indeed whether it improves inference at all. When

[260] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 7.

[261] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 20.

[262] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 20.

[263] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 21.

> it comes to actually doing the model averaging, there are two subtly different approaches that can produce quite different results.[264]

1512. In summary, the ERA considers the sensitivity of the model outcomes to the selected threshold, and discretionary approach proposed by Western Power in selecting a threshold value, is not consistent with the requirements of the Access Code.

Consistency of the estimated service standard benchmarks

1513. In proposing the model averaging method for deriving service standard benchmarks, Western Power compared the 99th percentile values for two distributions fitted to a five-year rolling window of a 12-month moving sum data set for the SAIDI Rural short performance measure, from 2012 to 2017, observing four transition points in which the lowest AIC value alternated. Western Power concluded that the distribution of best fit will change over time.[265]

1514. Western Power stated that the change in the distribution of best fit would result in a variation in the derived service standard benchmark by 10 to 20 per cent, that the model averaging method would overcome the volatility introduced by small changes to the data and ensure the setting of more consistent service standard benchmarks, over time:

> 337. To overcome the volatility introduced by small changes to the data Western Power proposes averaging all distributions considered to be a good fit.
>
> 338. We consider the methodology for averaging distributions for AA4 will ensure more accurate estimation of the probability of these compliance measures being met, provide appropriate incentives for Western Power to maintain compliance under the service incentive framework, and ensure the setting of more consistent SSBs over time all else being equal.[266]

1515. The technical report prepared by Analytics + Data Science used similar reasoning to propose averaging the percentile values of candidate distributions to provide stability to the service standard benchmarks and targets over time:

> The instability created by relying solely on a single distribution is undesirable. It creates uncertainty for customers and Western Power on what level of performance should be achieved during AA4, at a time when Western Power is seeking only to maintain existing service standards in line with customer expectations.[267]
>
> …
>
> Averaging a number of valid candidate distributions provides stability to the SSB/SST measures over time as the underlying data changes.[268]

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[264] Symonds, Matthew, and Adnan Moussalli, "A brief guide to model selection, multimodel inference and model averaging in behavioral ecology using Akaike's information criterion", Behavioral Ecology and Sociobiology, Vol. 65, 2011, p. 18

[265] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 94, para. 334.

[266] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 95, paras. 337-8.

[267] Western Power, Access arrangement information, Attachment 6.1, Review of service standards methodology, 2 October 2017, p. 8.

[268] Western Power, Access arrangement information, Attachment 6.1, Review of service standards methodology, 2 October 2017, p. 9.

1516. Western Power also claimed in the technical appendix to the proposed access arrangement that a "radical change" in the service standard benchmarks would be observed "from one year to the next" due to "small changes" in the underlying data if a single distribution of best fit was selected, suggesting robustness would be improved by averaging all distributions considered to be a good fit:

> Given that reliability data is continuously evolving, there is the risk that small changes in the underlying data would result in the AIC indicating a different distribution. The result can be a radical change in SSB/SST benchmark from one year to the next, which would be contrary to the principles of benchmark setting. To help ensure robustness of the resulting benchmark introduced by small changes to the data, Western Power proposes averaging all distributions considered to be a good fit for a measure based on AIC scores close to the lowest score.[269]

1517. In the expert report submitted by Western Power in the revised proposal, Analytics and Data Science acknowledged the validity of the observation that the composition and number of distributions would also vary over time. Analytics + Data Science claimed, however, that the multi-model method will have less effect on the percentile estimates and should be preferred if intertemporal consistency is a priority:

> The ERA's observations are valid. The selection of candidate statistical models may change over time when using Western Power's methodology.
>
> However, 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.[270]

1518. Pink Lake Analytics assessed the consistency of the estimated service standard benchmarks over time using the Pitman Closeness test, which assumes that, as sample size increases, an estimated parameter value will converge to a true value. The test compares two estimated values and selects that which is closer to the true value, although Pink Lake Analytics advised that the measure should be interpreted cautiously.[271]

1519. Pink Lake Analytics found that the service standard benchmark derived from the single distribution of best fit was closer to the true value than that derived using the model averaging method proposed by Western Power in some data scenarios:

> In general, Pitman closeness was low for the Proponent's method of model averaging, principally because we measured strict closeness, insofar as an estimate has to be strictly less than the distance from the true parameter value than another estimate. However, as the Proponent's method is a committee method then for most simulations it returned a single best model, rather than an average of multiple models, whenever the single best model was found to have significantly lower AIC. Hence, Pitman closeness is much smaller for the Proponent's method under some of the data

[269] Western Power, Access arrangement information, Attachment 6.2 Fitting Distributions for AA4 Service Standard KPIs-Setting the Service Standard Benchmark (SSB) and Service Standard Target (SST), 2 October 2017, p. 12.

[270] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 7.

[271] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 9.

> scenarios than for the other measures… Pitman closeness was otherwise varied with data scenario.[272]

1520. Pink Lake Analytics also considered that Western Power's observation of volatility in the model selection criteria, rather than the underlying data set, was not sufficient to justify the application of the model averaging method:

> The Proponent suggests also that the large volatility in AIC in response to small changes in data is justification for applying model averaging. While this statement has some legitimacy, it does not consider the sensitivity of the underlying distribution generating the data to small changes in the data…
>
> Clearly, if two competing models have different SSB estimates, and the first best model repeatedly switches between these two models depending on yearly random shifts in the data, then there is going to be high volatility in the SSB estimate. However, this can be argued to be a reflection more of volatility in the underlying distribution of service events (even after data have been smoothed with a 5-year rolling average) than any inherent volatility introduced by a switching first-best model estimate of the SSB. This argument is supported by the minimal observed difference between the single best AIC model and the Proponent's AIC model averaging method, as measured by the statistical performance measures.[273]

1521. The ERA further considers that the prioritisation of intertemporal stability is not necessarily consistent with the requirements of the Access Code. Western Power's expert report prepared by ACIL Allen also stated that variability in service performance between regulatory periods has been an observed and intended outcome of the service incentive scheme in Victoria:

> It is my opinion that the changes in the targets for each of the performance measures in the service incentive scheme over the 2000 to 2020 period indicate that:
>
> — the service performance varies from regulatory period to regulatory period, and from distribution network service provider to distribution network service provider
>
> …
>
> — service performance can jump around from one regulatory period to the next – where improvements in service performance are not sustained, the rewards paid by customers to the distribution network service providers are returned by way of penalties in the following period.[274]

1522. The technical report prepared by Analytics + Data Science also acknowledged that exogenous factors operating at discrete time periods affect observed service performance:

> If a longer time horizon were to be chosen, it would then be necessary to apply relevant adjustments to the time series data to take account of exogenous changes in regulatory and financial incentives. In this situation, we recommend that Western Power adopts the principle of parsimony by retaining the five-year duration, rather than

[272] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 15.

[273] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, pp. 22-3.

[274] Western Power, Revised proposed access arrangement information, Attachment 14.1, ACIL Allen Consulting Report on the Service Standards Adjustment Mechanism, 14 June 2018, p.11.

> choosing an arbitrarily long period and then attempting to control for the exogenous effects of capital expenditure and changes in incentive frameworks.[275]

1523. The ERA also considers:

- The data set used to derive service standard benchmarks is not "continuously evolving", as suggested by Western Power. Service standard benchmarks are derived from probability distributions fitted to a determinate set of historical performance data. Western Power has also elaborated on the undesirability of rolling performance benchmarks in its response to the draft decision.[276]

- The claim of a 10 to 20 per cent variation in the 99th percentile value of the first- and second-best probability distributions is overstated. Simple analysis of the difference between the 99th percentile of the first and second selected distributions of performance measures provided by Western Power reveals a maximum difference of less than 8 per cent, in the case of the SAIFI Urban performance measure, and much less in most cases.

- Western Power appears to have premised its proposal on the analysis of a single performance measure.

1524. Consequently, the ERA considers Western Power's claims of improved intertemporal stability of the model averaging method to be unsupported.

Statistical robustness of the multi-model averaging method proposed by Western Power

1525. Western Power cited the expert report produced by Analytics + Data Science within the revised proposal, which states the multi-model averaging method is desirable if it results in a more robust estimation of the service standard benchmarks than would be achieved by a single statistical model:

> The objective underpinning the distribution fitting process is not to attempt to identify the one single "true" model. Instead, the methodology should accurately model, as far as is practicable, those physical processes that drive SSB/SST variability in a consistent and replicable manner. For this reason the use of 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.[277]

1526. Western Power did not provide objective substantiation of the improved statistical robustness of the service standard benchmarks derived by the model averaging method.

1527. Pink Lake Analytics applied a local shift sensitivity test to assess the comparative robustness of the estimated service standard benchmarks proposed by Western Power against alternative estimation methods, including:

[275] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p.94, para.334

[276] Western Power, Revised proposed access arrangement information, 14 June 2018, p. 162, para. 339.

[277] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p.4.

- The single probability distribution of best fit.
- The Burnham-Anderson Information Theoretic Approach (BAITA).
- The kernel density method.

1528. The local shift sensitivity test measures the effect of perturbing a data point by differing amounts, with a lower sensitivity preferred to a higher sensitivity. Pink Lake Analytics concluded that the BAITA method was more robust than the proposed model averaging method and the single probability distribution of best fit, although the differences in local shift sensitivity were small. The kernel density estimate was found to be more robust than other methods:

> BAITA may be considered as comparatively more robust than the Proponent's proposed method or the single best method, although the differences in local shift sensitivity were minimal. Moreover, estimates of the 97.5th quantile were observed to be more robust (i.e., have lower local-shift sensitivity) than the 99th quantile (Tables 4-11). The kernel density estimate was found to be more robust than any other of the other estimates, largely because as a locally weighted estimator less weight is generally given to extreme observations than for a distribution whose estimate of the scale and centre may be highly influenced.[278]

1529. Western Power also referred to the single probability distribution of best fit, as required in the draft decision and applied in the third access arrangement period, top be inconsistent with a standard approach.[279] Analytics + Data Science also referred to the proposed model averaging method being consistent with state-of-the-art practice in statistical inference:

> The specification of one particular model as the "best" model for determining SSB/SST percentile values is inconsistent with the standard approach used by peer reviewed studies into statistical inference.
>
> …
>
> Burnham & Anderson (2004) provide a more complete discussion of the conclusions from multiple studies that demonstrate that a multimodel averaging approach is superior to the methodology in which parameter estimates are obtained from only the single "best" model.
>
> Consequently, a+ds considers that Western Power's decision to base percentile values on a multimodel approach is consistent with the state-of-the-art practice in statistical inference.[280]

1530. Pink Lake Analytics identified the absence of numerical measures of statistical performance to support claims of the model averaging method being consistent with best practice, and superior to the single distribution of best fit, as a "key weakness" of Western Power's proposal.[281]

1531. In addition to the minimal improvements of the model averaging method over the single distribution of best fit, Pink Lake Analytics concluded the proposed method is

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[278] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 15.

[279] Western Power, Revised proposed access arrangement information, 14 June 2018, p.158, para. 916.

[280] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 4.

[281] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. iii.

flawed from a statistical perspective because no measure of uncertainty has been provided by Western Power to demonstrate the statistical superiority of its proposed service standard benchmarks:

> The Proponent's methodology is flawed from a statistical perspective insofar as the Proponent provides no measure of uncertainty associated with their SSB estimate. The need for statistical performance measures to be associated with SSB estimates may be deemed as 'reasonable' under the Act, and as part of statistical best practice. It is also noted that past practice has not associated standard error measures with the SSB estimates. However, to demonstrate the statistical 'superiority' of a proposed estimator over and above the current methodology one must necessarily employ measures of statistical performance.[282]

1532. The principal authors in the field of model averaging have also emphasised the importance of objective, numerical measures to assess the statistical superiority of estimates derived by one method over another:

> Providing quantitative information to judge the "strength of evidence" is central to science.[283]

1533. In conclusion, the ERA considers:

- The improved accuracy of the service standard benchmarks proposed by Western Power has not been objectively or conclusively demonstrated.
- The sensitivity of the model outcomes to the selected threshold, and discretionary approach proposed by Western Power in selecting a threshold value is not consistent with the requirements of the Access Code.
- The claims of improved intertemporal stability of the model averaging method proposed by Western Power are unsupported.
- The improved statistical robustness of the method proposed by Western Power relative to the method applied in the third access arrangement period has not been objectively demonstrated.

1534. Consequently, the method of model averaging proposed by Western Power to derive service standard benchmarks is not consistent with the requirements of the Access Code and is not approved.

1535. Western Power must derive service standard benchmarks from the single probability distribution of best applied to five-years of performance data corresponding to the third access arrangement period.

Required Amendment 31

Western Power must use the single probability distribution of best fit to derive service standard benchmarks.

[282] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 23-4.

[283] Kenneth P. Burham and David R. Anderson, Multimodel Inference: Understanding AIC and BIC in Model Selection, Sociological Methods & Research, Vol. 33, No. 2, November 2004, p.266.

Setting the service standard benchmarks at the 99th (or 1st) percentile of the distribution of best fit

1536. Western Power proposed to set the service standard benchmarks for the distribution and transmission networks at the average of the 99th percentile of the fitted distributions for the fourth access arrangement period, or 1st percentile for call centre performance and circuit availability performance measures.[284]

1537. The proposed method contrasts with that applied in the third access arrangement period, in which service standard benchmarks were set at the 97.5th (or 2.5th) percentile of the distribution of best fit.

1538. The ERA considered that, although customers in general have expressed satisfaction with current levels of service performance, a small proportion of customers may be consistently receiving below-standard service. The ERA did not consider the proposal to set service standard benchmarks at the 99th (or 1st) percentile to be reasonable.

1539. The ERA did not approve the proposal to set service standard benchmarks at the 99th percentile, or 1st percentile for call centre performance and circuit availability. The ERA required Western Power to set service standard benchmarks at the 97.5th percentile, or 2.5th percentile of the single distribution of best fit in the draft decision:

> **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 revised proposal

1540. Western Power did not accept the required amendment and maintained its initial proposal to set the service standard benchmarks at the average of the 99th (or 1st) percentile of probability distributions fitted to monthly rolling-sum performance data corresponding to the third access arrangement period.

1541. Western Power stated that it intended to maintain service performance at an average level achieved in recent years and was seeking to avoid any reliability driven investment to meet minimum compliance targets:

> 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, 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. 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

[284] Western Power, Access arrangement information, Access arrangement revisions for the fourth access arrangement period, 2 October 2017, page 96, paragraph 339.

> meet the compliance targets, and would have minimal need to invest to improve average service levels.[285]

Further submissions

1542. Western Australia Major Energy Users supported the required amendment to set the service standard benchmark levels at the 97.5th percentile (or 2.5th percentile for circuit availability and call centre performance):

> While supporting all the changes ERA proposes for the service standards and their targets, WAMEU considers that the ERA should implement a requirement that the 97.5th percentile for all reliability benchmarks except circuit availability which is to be at the 2.5th percentile (call centre performance excluded).[286]

1543. Western Australia Major Energy Users also proposed that performance benchmarks should be revised annually such that recent service performance achieved is automatically rolled into the new benchmark:

> While WAMEU supports these benchmarks, it considers that the benchmark should be assessed on the basis of a rolling 5 year performance so that the benefits of later performances are automatically rolled into the benchmark. As the benchmarks are incentivised to show a continuing improvement in performance, the rolling 5-year performance approach provides continuing pressure to improve performance and limits the ability of WP to get easy bonuses.[287]

1544. The ERA has considered Western Australia Major Energy Users proposal to implement annually revised performance benchmarks and targets at paragraphs 1898 to 1907.

Considerations of the ERA

1545. Service standard benchmarks have three purposes under the Access Code:

- As minimum performance standards under section 11.1, which requires a service provider to provide reference services at a service standard at least equivalent to the service standard benchmarks set out in the access arrangement, subject to civil penalties for non-compliance (under section 11.6).

- As a collective minimum performance requirement to maintain eligibility for an above-benchmark surplus under the gain share mechanism (section 6.26).

- As the reference service standard specifying how performance will be treated under the service standard adjustment mechanism at the next access arrangement review (section 6.29).

1546. For the purpose of the service standard adjustment mechanism, service standard benchmarks were established as penalty caps in the third access arrangement period, and set at the 97.5th percentile value of the probability distribution of best fit

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[285] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 159, paras. 921-2.

[286] Western Australian Major Energy Users, Response to the ERA Draft Decision, May 2018, p. 55.

[287] Western Australian Major Energy Users, Response to the ERA Draft Decision, May 2018, p. 55.

to 12-monthly rolling-sum performance data (or 2.5th percentile in the case of circuit availability and call centre performance).

1547. The justification for capping penalties at the service standard benchmark level of performance under the service standard adjustment mechanism was to avoid the double penalty that applied due to the above-benchmark surplus being foregone under the gain share mechanism if any single service standard benchmarks was not achieved in each year:

> If the performance is worse than the service standard benchmark, no additional financial penalty will apply under SSAM than applies when the performance is at a minimum standard. This is because a significant disincentive already exists in the form of the potential to be noncompliant with our licence and the fact that we forego any additional rewards under the gain sharing mechanism for achieving cost efficiencies.[288]

1548. The ERA considered the disproportionate penalty under the gain share mechanism to be the primary factor in approving the proposal to cap penalties at the service standard benchmark level of performance under the service standard adjustment mechanism for the third access arrangement period.[289]

1549. Western Power cited the results of its customer engagement program in proposing to set the service standard benchmark at the 99th percentile in the fourth access arrangement period. Customers had expressed, in general, an unwillingness to fund further investment in network reliability.[290]

1550. Western Power also stated that, for most performance measures, the difference between the 97.5th percentile and 99th percentile was not material:

> 345. Where the performance of a measure is relatively consistent over time, the difference between the average of the 97.5th percentile of the distributions of best fit and the average of the 99th percentile is not material. This impact is more significant for volatile measures such as CBD SAIDI.[291]

1551. Western Power did not substantiate a numerical threshold of materiality or volatility.

1552. Consequently, the ERA considered customers' expressed preferences to be the primary factor in the draft decision requiring Western Power to maintain service standard benchmarks at the 97.5th (or 2.5th) percentile of historical performance data.

1553. Customer insight 13, for example, indicated that, although customers were not willing to fund an increase in broad network reliability, customers valued improved reliability in poorly served areas:

> The majority of our customers (61 per cent) told us that an increase in their annual bill of $10 was justified to improve the reliability of the electricity supply across remote areas of WA.[292]

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[288] Western Power, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 95.

[289] Economic Regulation Authority, Draft decision on proposed revisions to the access arrangement for the Western Power network, 29 March 2012, pp.256-8, paras.1082-93.

[290] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 96.

[291] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 97, para. 345.

[292] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 99, para. 362.

1554. Western Power also acknowledged in its access arrangement information that, despite customers in general being satisfied with existing levels of reliability, pockets of the network remained under-serviced:

> 15. Insights from the customer engagement program have shaped our thinking on the services we will provide and the technology we will invest in over the AA4 period. For example, customers have told us they don't necessarily want us to improve overall levels of reliability, but they are happy for us to target expenditure on pockets of the network where reliability is lower than average – so all customers receive a reliable source of electricity.[293]

1555. Western Power did not reference the gain share mechanism as a factor for consideration in its proposal to set service standard benchmarks at the 99th (or 1st) percentile value, although it did reference broad compliance objectives.

> 340. Western Power has a strong culture of compliance and aims to meet all SSBs in each year. Setting the SSBs on the basis of the 99th percentile better aligns with this objective.
>
> 341. By design, setting the SSB from the 97.5th percentile should result in a 2.5 per cent likelihood of being non-compliant with each metric, assuming stable performance. Setting the SSBs at the 99th percentile will increase Western Power's overall likelihood of being compliant with the requirements under the Access Code and therefore our electricity distribution and transmission licences.[294]

1556. It is apparent from Western Power's initial and revised proposals that collective compliance with service standard benchmarks to ensure eligibility for the above benchmark surplus under the gain share mechanism is a more significant factor motivating compliance with minimum service standards than the constant marginal penalty structure of the service standard adjustment mechanism. Western Power's proposal to increase the percentile value at which service standard benchmarks are set would also increase its exposure to penalties for sub-benchmark performance under the service standard adjustment mechanism.

1557. In its revised proposal, Western Power also referenced advice provided to the ERA by GHD Advisory that recommended acceptance of Western Power's proposed service standard benchmarks for most of the performance measures.[295]

1558. Western Power also stated in its revised proposal that the ERA had not demonstrated that its proposal to set service standard benchmarks at the 99th (or 1st) percentile did not meet the requirements of 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.

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[293] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 4, para. 15.

[294] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 96, paras. 340-1.

[295] GHD Advisory, Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, p. 247

> 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.[296]

1559. Section 5.6 of the Code requires service standard benchmarks to 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. Section 11.1 requires the service provider to comply with service standard benchmarks as minimum service standards, and section 4.28 requires the ERA to determine whether a proposed access arrangement meets the Code objective.

1560. Consequently, the ERA has considered the following matters in determining the consistency of Western Power's proposal to derive service standard benchmarks at the 99th percentile of five-years of performance data, corresponding to the third access arrangement period, with the Access Code:

- Customer preferences and the ability of minimum service standards to achieve reliability improvements in poorly served areas.
- Compliance with service standard benchmarks to ensure eligibility for the above benchmark surplus under the gain share mechanism.
- Western Power's data aggregation method.
- Clause 7.4.6 of the revised proposed access arrangement.

Customer preferences and worst served customers

1561. In its initial proposal, Western Power stated its intention to simultaneously target investment in worst served areas and maintain overall performance at current levels:

> Some pockets of the network do experience poorer service than others, particularly at the edge of the grid, therefore we will target investment to improve performance in those areas. However, our proposal is that the service incentive framework be designed to provide an incentive for Western Power to keep overall performance at current levels. [297]

1562. In its revised proposal, Western Power stated that, since service standard benchmarks apply to average levels of performance, the application of the 97.5th percentile, rather than the 99th percentile, will not guarantee an improvement of the level of service provided to each customer, including the worst served customers.[298]

1563. Western Power cited its export report, prepared by Analytics + Data Science, which stated that the requirement to set the service standard benchmark at the 97.5th percentile would not achieve the objective of improving service performance to worst served customers:

> Modifying the SSBs to use the 97.5th percentile does not guarantee an improvement in service standards to each and every customer. It is not a targeted incentive

[296] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 162-3, paras. 940-2.

[297] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, pp. 73-4, para. 238.

[298] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 160.

> mechanism. 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.[299]

1564. ACIL Allen Consulting also considered the design of the service incentive scheme, which rewards average performance, to be its main limitation:

> In my opinion, the main limitation of the service incentive scheme, as currently designed, is that it rewards ***average*** service performance only. It, in effect, biases any performance improvements to those feeders or feeder sections that impact a relatively large number of customers. Improvements that impact a small number of customers do not have a material impact on the average SAIDI or SAIFI.[300] [emphasis in original]

1565. Analytics + Data Science reiterated that a change in the average level of service performance may not improve the level of service to those customers experiencing a higher number of outages, because it is not a targeted mechanism:

> The ERA noted a preference for an improvement in the level of service to specific customers (not customers on average), and propose to achieve this outcome with a 97.5th percentile SSB. However, in the view of a+ds, adoption of the 97.5th percentile SSB will not necessarily ensure an improvement in service standards for those targeted customers, given it is an aggregate rather than targeted mechanism. For these reasons we see no rationale for not adopting the 99th percentile SSB value consistent with Western Power's proposed approach.[301]

1566. Analytics + Data Science had previously stated that Western Power should not be penalised for maintaining service performance and that it is not aware of any statistical basis for the choice of threshold:

> We note that Western Power's objectives for the coming five-year period is to maintain current service standards performance in line with customer expectations. Given that objective, it is appropriate to choose a percentile value that does not penalise Western Power for not continuing to improve performance. Choosing a lower threshold value would increase the probability that, in the absence of further investment (at the expense of customers), service standards would not be met and Western Power would be financially penalised.
>
> We are also not aware of any statistical basis which would suggest the 99th percentile value to be any more or less appropriate than an alternative threshold.[302]

1567. Pink Lake Analytics agrees that Western Power should not be penalised for maintaining an average level of service performance, but also identified that worst served customers are at a higher risk of receiving a lower standard of service if service standard benchmarks are set at the 99th percentile not the 97.5th percentile of past performance:

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[299] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 8.

[300] Western Power, Revised proposed access arrangement information, Attachment 14.1, ACIL Allen Consulting Report on the Service Standards Adjustment Mechanism, 14 June 2018, p. 17.

[301] Western Power, Revised proposed access arrangement information, Attachment 13.1, Analytics + Data Science Report on Methodology for setting the service standard benchmarks and targets, 14 June 2018, p. 10.

[302] Western Power, Access arrangement information, Attachment 6.1, Review of service standards methodology, 2 October 2017, p. 10.

> Advice to the Proponent that lower SSBs do not guarantee improved services for all customers is specious, principally because it was not demonstrated that higher SSBs guarantee improved services for all customers. If anything, a relaxation of the SSB through employing a more extreme quantile will diminish the provision of services to customers simply because less will need to be invested to satisfy the SSB (as indicated by higher Type II error rates for the 99th quantile). The Proponent has considered only Type I error (false positives) and not Type II error (false negatives).[303]

1568. While it is correct that setting minimum performance benchmarks at the 97.5th percentile of historical performance will not guarantee improved service performance to worst served customers, it does not follow that an improvement in the minimum level of service performance will not benefit worst served customers.

1569. In conclusion, the ERA considers that, although setting service standard benchmarks at the 97.5th percentile does not guarantee that worst served customers will receive a higher service standard, worst served customers are at a higher risk of receiving a lower standard of service if service standard benchmarks are set at the 99th percentile.

Cumulative compliance with service standard benchmarks

1570. In its revised proposal, Western Power stated that, based on performance during the third access arrangement period, it no longer considered the service standard benchmark at the 97.5th percentile of historical performance to be an acceptable risk:

> 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. We therefore no longer consider that setting the SSBs at the 97.5th (or 2.5th) percentile would reflect a minimum service standard.

1571. Western Power stated that its options for mitigating the risk of non-compliance with service standard benchmarks were to adjust the percentile value at which service standard benchmarks are determined, or incur additional expenditure.[304]

1572. Pink Lake Analytics considered the effect of non-compliance with any single service standard benchmark to be the principal factor in Western Power's proposal to increase the percentile value at which service standard benchmarks are set from the 97.5th percentile to the 99th percentile:

> The core of the Proponent's argument for increasing the SSB from the 97.5th quantile to the 99th quantile is to avoid the issues surrounding the multiple trial problem, which focuses on the Type I error rate.[305]

1573. Pink Lake Analytics described the problem in terms of the following false error rates:

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[303] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 24.

[304] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 159.

[305] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 18.

- A Type I error, or false positive error, occurs when the service performance indicator fails to register above the minimum benchmark performance due to a random factor, when in fact the underlying level of performance has not deteriorated below the benchmark level of performance.

- A Type II error, or a false negative error, occurs when the performance measure fails to detect a breach of the minimum service standard, when in fact sub-benchmark performance has occurred.[306]

1574. Pink Lake Analytics explained the problem faced by Western Power when non-compliance with a single performance benchmark is exacerbated by multiple performance measures with a significant penalty for non-compliance:

> In the multiple trial problem a service provision indicator may exceed the SSB simply through randomness, without there being an actual worsening in the service provision itself (i.e., a false positive). This is not necessarily a problem if only a single SSB is being considered. However, if multiple SSBs are considered, and the Proponent is penalised whenever at least one SSB is breached, then the odds of at least one false positive occurring across all of the SSBs begin to compound. Hence, when a market actor can get penalized on one of many indicators the false positive rate (Type I error), and hence the expected penalty, can be significantly higher than the nominal Type I error rate defined for a single SSB.[307]

1575. Pink Lake Analytics concluded that Western Power's proposal to set the service standard benchmarks at the 99th percentile would reduce the risk of a performance measure registering a breach of the service standard benchmark as a chance occurrence (Type I errors):

> The Proponent is correct in that implementing a lower quantile will lead to a higher rate of not satisfying the collar SSB through chance variation. This is because there are multiple service performance indicators at play. In this instance, the chance of at least one performance indicator breaching its respective SSB (this chance increases with the number of performance indicators applied) can be much greater than the chance of a single performance indicator breaching its SSB.[308]

1576. Pink Lake Analytics also concluded, however, that Western Power's proposal to increase the percentile value at which service standard benchmarks are set does not adequately consider the Type II error rate, which may be unacceptably high:

> The solution here is not necessarily to increase the SSB to adjust for the higher false positive rate of multiple indicators (i.e., the service performance indictor is greater than the SSB simply through chance). Instead, setting a target for the false positive rate by allowing multiple indicators to breach their respective SSBs may be considered. For example, applying the collar when at least two service performance indicators breach their SSBs may be preferable to applying the collar when at least one service performance indictor breaches an SSB that is set at a higher level. This is because the Type II error rate (i.e., false negatives) may be unacceptably high with a higher SSB quantile. The proponent considers only Type I errors under the multiple trial problem, and does not consider costs associated with Type II errors.[309]

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[306] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 6.

[307] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 18.

[308] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 24.

[309] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, pp. 24-5.

1577. Pink Lake Analytics' conclusions were based on the theoretically consistent finding that more extreme percentile estimates are associated with higher levels of uncertainty:

> The 99th quantile was in all cases associated with larger standard errors and greater prediction error than the 97.5th quantiles… More significantly, the Type II error rate was much smaller for the 97.5th quantiles than for the 99th quantile estimates. Taken together, the implication is that the 97.5th quantile provides a more reliable estimator across the different statistical performance indicators, primarily because the 97.5th quantile is better able to correctly detect a shift in the underlying distribution if service standards worsen, and without overly penalising good service provision by an unnecessarily high Type I error rate… This finding is supported by theory, whereby the estimation of extreme quantiles is associated with greater uncertainty.[310]

1578. Pink Lake Analytics listed the following additional concerns and recommended the proposal to increase the percentile level at which service standard benchmarks are set, from the 97.5th percentile to the 99th percentile, be rejected:

- The higher degree of uncertainty associated with the 99th percentile.
- The correlation between performance measures has not been accounted for, and likely overestimates the Type I error rate.
- Type II errors, where sub-benchmark performance remains undetected, have been ignored.
- The relative costs of Type I errors and Type II errors have not been assessed.[311]

1579. Having regard to the analysis and concerns listed by Pink Lake Analytics, the ERA considers Western Power's has not demonstrated its proposal to set service standard benchmarks at the 99th percentile to comply with the requirements of the Access Code.

Western Power's data aggregation method

1580. In the technical appendix to its initial proposal, Western Power referred to the importance of the assumption of independence of each observation to the validity of the model-fitting process, and the effect on estimated parameters if underlying assumptions are violated:

> If dividing the data in different ways leads to radically different results, then it can be reasonably inferred that the underlying assumptions are grossly violated. In such cases, additional information needs to be obtained to better understand the Data Generating Process. Once this is obtained, an agreed mitigation strategy to adjust the data can be implemented. Note that no agreed mitigation strategy to adjust the data has been implemented.[312]

[310] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 12.

[311] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. iv.

[312] Western Power, Access arrangement information, Attachment 6.2 Fitting Distributions for AA4 Service Standard KPIs-Setting the Service Standard Benchmark (SSB) and Service Standard Target (SST), 2 October 2017, p. 9.

1581. Western Power also referred to the technical report prepared by GHD Advisory for the ERA, which suggested the 99th percentile value was proposed by Western Power to compensate for the "narrower" dispersion of the probability distributions of the 12-monthly rolling sum data set:

> By using a 12-month rolling average dataset for the AA4 analysis, the probability distributions for a majority of the service measures have smaller standard deviations, making the distributions "narrower". 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.[313]

1582. GHD Advisory's analysis and comparison of the percentile values used in the third access arrangement period, however, was based on an incorrect belief that Western Power had used only five annual performance results to derive service standard benchmarks at the 97.5th percentile during the third access arrangement period:

> In establishing the SSBs for AA3, we believe that Western Power adopted the 97.5th percentile value based on probability distributions that were fitted to five annual performance results.[314]

1583. Pink Lake Analytics was requested to evaluate the validity of the data construction method adopted by Western Power to derive percentile estimates for the purpose of establishing service standard benchmarks.

1584. Similar to GHD, Pink Lake Analytics noted that the data aggregation method used by Western Power results in an underestimated variance of the underlying process:

> Autocorrelation will mean a variance estimate will underestimate the true variance, including both the standard error and prediction error estimates of each SSB estimation procedure. As a consequence Type II error rates will likely be higher and Type I error rates lower, given a positive bias.

1585. Pink Lake Analytics concluded that the bias caused by the data aggregation method at the 99th percentile increased slightly when compared to the 97.5th percentile, and to a large degree when compared to percentile estimates derived from daily data:

> Bias increased slightly for the 99th quantile estimates compared to the 97.5th quantile estimates. Bias increased to a large degree when data were aggregated as monthly 12-month rolling averages when compared to quantiles generated from the daily data.
>
> Overall, 99th quantiles produced less stable estimates than 97.5th quantile estimates, as indicated by poorer performance across most of the statistical performance metrics.[315]

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[313] GHD Advisory, Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, p. 247.

[314] GHD Advisory, Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, p. 246.

[315] Pink Lake Analytics, Evaluation of the method proposed by Western Power to calculate service standard benchmarks for the fourth access arrangement period, August 2018, p. 15.

1586. Having regard to the analysis presented by Pink Lake Analytics, the ERA considers Western Power's proposal to set service standard benchmarks at the 99th percentile is not a reasonable mitigation strategy to overcome the systematically underestimated volatility of the service performance measures.

Section 7.4.6 of the revised proposed access arrangement

1587. Section 6.26 of the Access Code states that an above benchmark surplus does not exist to the extent that efficiency gains or innovation in excess of the efficiency and innovation benchmarks during the previous access arrangement period were achieved by failing to comply with minimum service standards specified at the service standard benchmark level of performance under section 11.1.

1588. Clause 7.4.6 of the revised proposed access arrangement was inserted in the third access arrangement period. The clause enables Western Power to demonstrate how and to what extent any failure to provide reference services at a service standard at least equivalent to the service standard benchmark level of performance was related to the achievement of relevant efficiency gains or innovation in excess of the efficiency and innovation benchmarks in any year.

1589. The information is used by the ERA to determine the extent to which Western Power achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks for the purpose of establishing the existence of an above benchmark surplus under section 6.26 of the Access Code.

1590. The ERA noted in the final decision for the third access arrangement period that the circumstances leading to failure to achieve service standard benchmarks will vary and the onus of proof remained with Western Power to demonstrate that non-compliance with the minimum service standard was not related to the attainment of an above benchmark surplus under the gain share mechanism:

> The Authority notes, in the event of any failure to meet service standard benchmarks, Western Power bears the onus of proof to demonstrate that any above-benchmark surplus has arisen due to the failure to meet service standard benchmarks.[316]

1591. The ERA's technical consultant considered the effect of this provision to imply that failure to achieve a service standard benchmark in any year did not mean that Western Power would forfeit its share of any operating expenditure gains to which it may otherwise be entitled.[317]

1592. The ERA's technical consultant considered that a regulatory framework predicated on the assumptions that Western Power has a high degree of control over service standard outcomes, and that there is a strong correlation between service performance and operating expenditure, to be flawed for the following reasons:

- Environmental conditions over which WP management has no control can have a strong influence on the service levels that the network is able provide. While it is possible to design a network to mitigate environmental factors, this can be uneconomic. A balance must therefore be struck between service level and cost. Occasionally a high impact low probability (HILP) event will occur where the impact is so severe that service levels falls well below the level the network is designed to deliver. In such circumstances the measured service levels are

[316] Economic Regulation Authority, Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, 5 September 2012, p. 482, para. 2118.

[317] Geoff Brown & Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018

statistical outliers. This is a problem for all network operators and is not an issue unique to WP.

- The correlation between network service levels and operational expenditure in the same year is relatively weak as evidenced by Western Power's performance during AA3. In two of the five years of AA3, WP achieved all its 17 SSBs. In each of the other years it met 16 of the 17 SSBs and failed to meet one. Significantly, the two years where its opex was higher than the GSM benchmark so that it didn't qualify for a GSM reward were years in which it failed to meet an SSB.[318]

1593. The ERA considers clause 7.4.6 of the access arrangement contract provides Western Power sufficient scope to demonstrate that the failure to achieve a service standard benchmark in any year was not related to the achievement of efficiency gains or innovation in excess of the efficiency and innovation benchmarks in any year. On this basis, the failure to achieve a service standard benchmark in any year does not automatically forfeit Western Power's eligibility to claim the above benchmark surplus.

1594. In conclusion, the ERA consideres the following factors in determining that Western Power's proposal does not comply with the requirements of the Access Code:

- Worst-served customers are at a higher risk of receiving a lower standard of service if service standard benchmarks are set at the 99th percentile.

- Western Power has not sufficiently demonstrated the compliance of its proposal to set service standard benchmarks at the 99th percentile to be consistent with the Access Code.

- Setting service standard benchmarks at the 99th percentile, rather than the 97.5th percentile, is not a valid strategy to mitigate the underestimated performance volatility caused by Western Power's data aggregation method.

- Clause 7.4.6 of the access arrangement contract provides Western Power sufficient opportunity to demonstrate that the failure to achieve a service standard benchmark in any year was not related to the achievement of efficiency gains or innovation in excess of the efficiency and innovation benchmarks in any year. The above benchmark surplus is not automatically forfeited if service standard benchmarks are not met in any year.

1595. Western Power must derive service standard benchmarks at the 97.5th (or 2.5th) percentile of a single probability distribution of best fit to historical performance data.

Required Amendment 32

Western Power must derive service standard benchmarks at the 97.5th percentile of the single probability distribution of best fit for SAIDI, SAIFI loss of supply event frequency and average outage duration performance measures, and at the 2.5th percentile for call centre performance and circuit availability performance measures.

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[318] Geoff Brown & Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018.

Maintaining the service standard benchmarks set for the AA3 period in the 2017/18 financial year

1596. Western Power proposed to maintain the service standard benchmarks set during the third access arrangement period for the 2017/18 financial year.

1597. The ERA considered the proposal to maintain service standard benchmarks for the 2017/18 financial year at the level set for the third access arrangement period to be reasonable and consistent with the Code objective.

1598. The ERA approved the proposal to maintain service standard benchmark levels set for the third access arrangement period for the 2017/18 financial year.

Western Power's revised proposal

1599. Western Power did not revise its proposal to maintain service standard benchmarks in the 2017/18 financial at the same levels as those applied third access arrangement period.

Further submissions

1600. No submissions were received addressing the maintenance of service standard benchmark from the third access arrangement period for the 2017/18 financial year.

Considerations of the ERA

1601. The ERA maintains the draft decision to approve the maintenance of service standard benchmarks from the third access arrangement period for the 2017/18 financial year.

Implementation of a service standard benchmark for momentary interruptions

1602. The ERA considered the implementation of a momentary average interruptions frequency index (MAIFI) 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.

1603. The ERA required Western Power to establish a service standard benchmarks and target and report performance for a momentary average interruptions frequency index for the fourth access arrangement period:

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 revised proposal

1604. Western Power did not accept the required amendment because:

- Momentary interruption data reported during the third access arrangement period is incomplete. Western Power estimated that 16 per cent of momentary interruptions were not recorded.

- The momentary interruption data reported during the third access arrangement period was not consistently recorded or reported.
- The definition of momentary interruptions is not clear.
- The inclusion of MAIFI as a service standard benchmark is not consistent with the requirements of the Access Code.

1605. Western Power proposed to report on a momentary interruption events ($MAIFI_e$) measure during the fourth access arrangement period, which would enable the measure to be implemented as a service standard benchmark during the subsequent access arrangement period based on five years of consistently reported data.

Further submissions

1606. No further submissions were received that addressed the draft decision to implement a momentary average interruptions frequency index performance measure during the fourth access arrangement period.

Considerations of the ERA

1607. The ERA considered each of the reasons provided by Western Power in its revised proposal to not set a service standard benchmark for momentary interruptions during the fourth access arrangement period. These are explained and considered in further detail below.

Incomplete momentary interruptions data

1608. Western Power stated that the telemetry, SCADA and communications systems required to record and report momentary interruptions were not installed during the third access arrangement period and are not planned to be installed in the fourth access arrangement period.

1609. Western Power stated the ERA did not approve the investment required to install devices, communications and interpretive systems in the final decision of the third access arrangement review. The draft decision to approve $32.3 million to replace SCADA and communications assets in the fourth access arrangement period do not improve Western Power's capability to record or report momentary interruptions.[319]

1610. Western Power further stated that it is not planning to install monitoring and communications equipment in the fourth access arrangement period and has not completed a detailed study of the program of works required to accurately report on MAIFI.

1611. Western Power also claims the reporting of MAIFI without a complete five-year data set would be problematic because:

- Reported data would not accurately reflect service performance experienced by customers.

[319] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 171, para. 985.

- It would create an incentive to meet an artificial service standard.
- It may not capture priority feeders.
- It would increase the probability of Western Power being non-compliant with the service standard benchmarks and therefore ineligible for the gain share mechanism.

Unvalidated momentary interruption data

1612. In addition to the reported network asset limitations, Western Power also claimed the following data processing and reporting limitations:

- An unclear definition of momentary interruptions.
- Manual cleansing and validation of momentary interruptions data.
- Subjective determinations of the MAIFI threshold.

1613. Western Power claimed that standardisation of definition, recording and reporting processes would be required to compile a consistent data set that accurately reflected historical performance.

Lack of clarity of the definition of MAIFI

1614. Western Power referred to recent debate about:

- The threshold duration in which an interruption would be considered momentary.
- Whether multiple interruptions should be classed as a single event.

1615. Western Power referred to the recommendation of the Australian Energy Market Commission, and subsequent proposal by the Australian Energy Regulator to amend the service target performance incentive scheme to define a momentary interruptions for the purpose of recording MAIFI as an interruption of less than three minutes.

1616. Western Power also referred to the Australian Energy Market Commission's support for the use of a MAIFI event measure ($MAIFI_e$) that recognises the effect of several momentary interruptions on customers to be marginal relative to the effect of the combined interruption 'event'.

1617. Western Power explained that the benchmarking of performance against a $MAIFI_e$ measure permits multiple attempts to restore supply without additional penalty, whereas a performance benchmark specified against MAIFI would only permit single auto reclose attempts and result in unnecessarily longer outages for customers.

1618. Western Power proposes to report on $MAIFI_e$ as the accepted industry measure.

Access Code requirements

1619. Western Power also claimed MAIFI does not currently meet requirements of the Access Code. Specifically, Western Power claimed the MAIFI data as recorded and reported in the third access arrangement period was not sufficiently detailed and complete, and would not enable users to determine the value represented by the reference service at the reference tariff, as required by section 5.6 of the Access Code.

Western Power's proposed reporting method for the fourth access arrangement period

1620. Western Power proposed to adopt the definition of momentary interruption data consistent with the MAIFIe formula:

$$\mathrm{MAIFI_e} = \frac{\sum \text{Momentary interruption events}}{\text{Total no. of distribution customers served}}$$

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.

1621. Western Power also proposed to apply the same exclusions to $\mathrm{MAIFI_e}$ as are applied to SAIDI and SAIFI.

1622. Western Power also explained that, should the MAIFI definition be changed to three minutes, the SAIDI and SAIFI interruption thresholds would also need to be amended to avoid duplication.

1623. Western Power also proposed that, should the ERA require MAIFI to be included as a service standard benchmark for the fourth access arrangement period:

- A single service standard benchmark be applied to the entire network, rather than by feeder category.
- The service standard benchmark be based on $\mathrm{MAIFI_e}$, rather than MAIFI.
- A step-change in the proposed service standard benchmark of 10 per cent to allow for existing data limitations.
- Additional operating expenditure of $1.3 million be approved to manage the service standard benchmark, including monitoring and reporting.
- Additional capital expenditure of $13.5 million to expand the telemetry system.
- Additional capital expenditure of $20 million to upgrade the communications network.

1624. Western Power also considered that $\mathrm{MAIFI_e}$ should not be included in the service standard adjustment mechanism due to the lack of robust data on which to set service standard targets.

1625. The ERA approves Western Power's proposal to record and report momentary interruption events, consistent with the proposed $\mathrm{MAIFI_e}$ formula, within the annual Service Standard Performance Report during the fourth access arrangement period, for the purpose of establishing service standard benchmarks and targets in the next access arrangement period.

1626. The ERA considers Western Power must record and report momentary interruption events by feeder category within the Service Standard Performance Report during the fourth access arrangement period, consistent with the categories of momentary interruptions reported in the Service Standard Performance Report .

1627. The ERA also considers the proposal to measure SAIDI and SAIFI during the fourth access arrangement period using existing and proposed new interruption thresholds to be reasonable.

Required Amendment 33

Western Power must record and report momentary interruption events, consistent with the proposed $MAIFI_e$ formula, within the annual Service Standard Performance Report during the fourth access arrangement period, for the purpose of establishing service standard benchmarks and targets in the next access arrangement period.

Required Amendment 34

Western Power must record and report momentary interruption events by feeder category within the Service Standard Performance Report during the fourth access arrangement period.

Permitted exclusions

1628. In a submission to Western Power's initial proposal, Mr Davidson raised objections to the list of exclusions currently permitted from distribution and transmission reliability performance measures within the proposed access arrangement.

1629. Mr Davidson's objected to the following exclusions from the SAIDI and SAIFI performance measures:

- Interruptions shown to be caused by a fault or other event on the transmission system.
- Interruptions affecting the distribution system shown to be caused by a fault or other event on a third party system.
- Planned interruptions caused by scheduled works.[320]

1630. Mr Davidson also considered the following events should not be excluded from the circuit availability service standard benchmarks:

[320] Mr Stephen Davidson, Submission TWO on Proposed Revisions to the Western Power Network Access Arrangement, 11 December 2017, p. 4.

- Zone substation power transformers.
- Interruptions caused by third party faults.
- Hours exceeding 14 days for planned interruptions for major construction work.[321]

1631. Mr Davidson also disagreed with the list of exclusions from the average outage duration performance measure.[322]

1632. In the draft decision, the ERA considered:

- That it is common practice to exclude events from reliability performance measures which are beyond the ability of the service provider to control.[323]
- That reliability of supply to the customer is distinct from the measurement of performance of the service provider.[324]
- That, although events may be excluded from distribution reliability indices, interruptions experienced by customers may still be reported.[325]
- The current service standard benchmarks and permitted exclusions, including separate reporting of excluded events, to 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.

Western Power's revised proposal

1633. Western Power did not submit a revised proposal referencing permitted exclusions from service performance measures.

Further submissions

1634. Mr Davidson made a further submission, which stated that zone substation transformers should not be excluded from transmission network performance benchmarks:

> Namely, the purpose of the transmission system is to provide injection points into the distribution system. The injection points are zone substations. The distribution system emanates from the perimeter fence of zone substations.

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321 Mr Stephen Davidson, Submission TWO on Proposed Revisions to the Western Power Network Access Arrangement, 11 December 2017, p. 4.

322 Mr Stephen Davidson, Submission TWO on Proposed Revisions to the Western Power Network Access Arrangement, 11 December 2017, p. 4.

323 Australian Energy Market Commission, Review of Distribution Reliability Measures, Final Report, 5 September 2014, p. 21.

324 Australian Energy Market Commission, Review of Distribution Reliability Measures, Final Report, 5 September 2014, p. 21.

325 Australian Energy Market Commission, Review of Distribution Reliability Measures, Final Report, 5 September 2014, p. 24.

> The distribution system does not and should not include zone substation equipment, and, certainly not equipment designed to withstand transmission voltages during normal operation, for example zone substation power transformers.
>
> A transmission circuit should encompass all primary (high current) equipment that injects power into the distribution system, including zone substation transformers.[326]

Considerations of the ERA

1635. In the draft decision for the first access arrangement period, the ERA required Western Power to remove zone substation transformers from the list of allowable exclusions from the circuit availability performance measure.

1636. In the final decision, however, the ERA accepted Western Power's representations that the proposed exclusions, including zone substation transformers were consistent with:

- Performance standards implemented elsewhere for transmission systems.
- Definitions of transmission assets either under the Access Code or according to conventions adopted by Western Power.
- Western Power's ability to include relevant parts of the network in measures of circuit availability.

1637. The ERA accepted, in principle, that consistency of the methods and exclusions in measurement of circuit availability by Western Power with the methods implemented in the National Electricity Market would assist users on the transmission network to determine the value of the service.

1638. The ERA also maintained the position that zone substation transformers should be removed from the list of exclusions for circuit availability, but accepted the practical limitations in implementing performance measures for the first access arrangement period. The ERA expected, however, that the reasonableness of the exclusions would be reviewed at the next access arrangement review:

> 158. The Authority maintains the position taken in its Draft Decision that there should not be any exclusion for zone substations connected to the transmission network via radial connections, nor for tee-configuration line circuits. However, the Authority also recognises that there are practical considerations in implementing performance measures, particularly for the first access arrangement period. Taking this into account, the Authority is prepared to accept that, for the first access arrangement period, the exclusions proposed by Western Power are reasonable and consistent with the requirements of the Access Code. The Authority expects, however, that consideration will be given to whether these exclusions remain reasonable when the access arrangement is revised.[327]

1639. The ERA's technical consultant to the review of the fourth access arrangement, Geoff Brown and Associates, was requested to provide advice on the reasonableness of Mr Davidson's proposal to remove zone substation transformers from the list of exclusions for the circuit availability and average outage duration

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[326] Mr Stephen Davidson, Submission TWO on Draft Decision on Proposed Revisions to the Western Power Network Access Arrangement – AA4, Attachment 3, 11 December 2017, p. 4.

[327] Economic Regulation Authority, Final Decision on the Proposed Access Arrangement for the South West Interconnected Network, 2 March 2007, p.

performance measures. Geoff Brown and Associates agreed with Mr Davidson's proposal:

> GBA agrees with Mr Davidson… zone substation transformers are defined as transmission assets in the Technical Rules and there is no obvious technical or regulatory reason why they should be treated any differently from other transmission assets in the measurement of service level.
>
> The Access Arrangement definitions for [circuit availability] and [average outage duration] exclude zone substation transformers but those for [system minutes interrupted] and [loss of supply event frequency] do not. GBA cannot see the rationale for this and… does not consider that zone transformer outages or faults should be excluded from any transmission service measure.[328]

1640. The Australian Energy Regulator does not exclude zone substation transformers from performance measures in the service target performance incentive scheme for transmission network service providers.[329]

1641. The ERA considers the exclusion of zone substation power transformers from transmission network performance measures is not consistent with the requirements of the Access Code.

1642. Western Power must remove zone substation power transformers from the list of exclusions for the circuit availability and average outage duration performance measures.

Required Amendment 35

Western Power must remove zone substation transformers from the list of exclusions for the circuit availability and average outage duration performance measures.

[328] Geoff Brown & Associates, Davidson Submissions, 16 August 2018

[329] Australian Energy Regulator, Final, Electricity transmission network service provider, Service target performance incentive scheme, Version 5 (corrected), October 2015.

ADJUSTMENTS TO TARGET REVENUE

Access Code requirements

1643. Sections 6.6 to 6.32 of the *Electricity Networks Access Code 2004* (Access Code) provide for the target revenue for an access arrangement period to include certain amounts "carried over" from the previous access arrangement period, including:

- An amount in respect of costs incurred as a result of a force majeure event under sections 6.6 to 6.8 of the Access Code.
- An amount in respect of costs incurred as a result of changes to the Technical Rules, for which no allowance was made in the access arrangement, under sections 6.9 to 6.12 of the Access Code.
- An amount under an investment adjustment mechanism under sections 6.13 to 6.18 of the Access Code.
- An amount under a gain sharing mechanism under sections 6.19 to 6.28 of the Access Code.
- An amount under a service standards adjustment mechanism under sections 6.29 to 6.37 of the Access Code.

Current access arrangement

1644. The current access arrangement includes the following mechanisms:

- Unforeseen events adjustment – an adjustment to account for costs incurred in the third access arrangement period (AA3) as a result of force majeure events.
- Technical rule change revenue adjustment – an adjustment to account for costs incurred as a result of changes to the Technical Rules that could not have reasonably been foreseen at the commencement of AA3.
- Investment adjustment mechanism – an adjustment to account for differences between forecast and actual costs of certain classes of new facilities investment.
- Gain sharing mechanism – an adjustment to account for the out-performance of the forecast operating expenditure in AA3.
- Service standards adjustment mechanism – an adjustment to account for any difference between service standard performance and service standard benchmarks in AA3.
- D-factor – an adjustment to account for any additional operating expenditure incurred which was a result of deferring a capital expenditure project and any additional operating or capital expenditure in relation to demand management initiatives.

- Deferred revenue from the second access arrangement period (AA2) – an adjustment to account for the amount of revenue deferred in AA2 which was to be recovered in subsequent access arrangement periods[330].
- Correction factor – a year-on-year adjustment to allowed revenue to account for under-recover or over-recovery of revenue under the revenue cap.

1645. The "Target Revenue" section of the draft decision (paragraph 171 and following) outlined the proposed adjustments to the fourth access arrangement period (AA4) target revenue for outcomes and events arising during AA3.

Western Power's initial proposal

1646. In its initial proposal, Western Power maintained the adjustment mechanisms included in the current access arrangement, but proposed amendments to each of them. The proposed amendments are discussed below under "Considerations of the ERA".

Submissions on Western Power's initial proposal

1647. Submissions received on Western Power's initial proposal are discussed below under "Considerations of the ERA".

Considerations of the ERA

1648. The ERA has considered Western Power's proposed amendments to the adjustment mechanisms in the following order.

- Force majeure
- Technical Rules
- Investment adjustment mechanism
- Gain sharing mechanism
- Service Standard adjustment mechanism
- D-Factor
- Deferred revenue.

Force majeure

1649. In its initial proposal, Western Power proposed to amend the specified force majeure events included in section 7.1.4 of the access arrangement as follows:

- Remove reference to the carbon pricing mechanism that was introduced in 2011 on the basis that it is no longer relevant. Western Power retained broader reference to "the introduction of any scheme or mechanism" to deal with emissions of greenhouse gases.

[330] The deferred revenue arose due to Western Power changing its treatment of capital contributions in the calculation of target revenue between AA1 and AA2.

- Remove the mandated roll-out of advanced meters as a specified force majeure event. Western Power instead proposed to include metering costs in the expenditure categories subject to the investment adjustment mechanism.
- Introduce a new specified force majeure event of “government-led reforms”.

1650. Western Power submitted the following reasons for electricity market reforms to be included:[331]

> Any Government-led reform, such as those proposed under the [electricity market reforms] some of which have recently been reaffirmed by the Minister for Energy[332], could have a significant impact on Western Power’s expenditure. As these would be mandated and largely outside of Western Power’s control, we should be provided with the opportunity to recover these costs either:
>
> - in-period using the trigger event provision to re-open the access arrangement
> - in the following access arrangement period using the unforeseen event provision.

Submissions on initial proposal

1651. Submissions on Western Power’s initial proposal were received from Community Electricity, CdL Advisory, Change Energy, Alinta Energy (Alinta) and Synergy.

1652. Community Electricity supported Western Power's proposed new force majeure event of "government energy reforms".[333]

1653. CdL Advisory and Change Energy did not support the proposed changes.

1654. Alinta raised concerns over the broad nature of Western Power’s proposal to include “any other government energy reforms”. It submitted the following:[334]

> Western Power has proposed to include <u>any</u> government energy reforms (Alinta <u>emphasis</u>) as a new unforeseen and trigger event. Alinta’s understanding is that these trigger events define when Western Power <u>has</u> to reopen an access arrangement. There could be any number of government energy reforms (i.e. a change to the metering code for example) that could in no way be defined as “so substantial that the advantages of making a variation to this access arrangement before the end of this access arrangement period outweigh the disadvantages”. The proposal that <u>any</u> government energy reform could reopen an access arrangement for reconsideration gives rise to significant and untenable regulatory uncertainty. Alinta values certainty, and as such, we advise caution against including such a broad and undefined trigger event.

1655. Synergy submitted that Western Power’s proposal was unclear and may result in the matters listed in section 7.1.4 being given force majeure status irrespective of whether the matters actually satisfy the definition of force majeure in the Access Code. It submitted the following:[335]

> WP's proposal at section 7.1.4 (as with its AA3 section 7.1.4 predecessor), is unclear, so that it may seem to confer "force majeure" status on the particular matters listed in

[331] Western Power, *Access Arrangement Information*, 2 October 2017, p. 112, paragraph 427.

[332] This includes the Minister for Energy’s re-affirmation to extend retail choice and move from an unconstrained to a constrained access regime by 2020.

[333] Community Electricity, *Response to ERA public consultation*, 10 December 2017, p. 1.

[334] Alinta Energy, Alinta Energy submission, 11 December 2017,

[335] Synergy, *Submission No. 5: Western Power’s proposed price control mechanisms*, 11 December 2017, p. 24.

> the section, irrespective of whether they actually satisfy the definition of "force majeure" under the Code. Synergy submits the Code does not allow an event to be a "force majeure" (and hence treated as an "unforeseen event") unless it satisfies the definition of "force majeure" in section 1.3 of the Code; and that definition may not be altered in an access arrangement when used for compliance with a matter required by the Code (such as dealing with adjustments for unforeseen events under sections 6.6 to 6.8 of the Code). In particular, listing of a specific matter in section 7.1.4 does not automatically confer on it the status of "force majeure" (or an "unforeseen event"). It must still satisfy the relevant tests for "force majeure" (and for an "unforeseen event"). Synergy therefore submits the drafting of WP's proposal at section 7.1.4 should be amended to clarify expressly that none of the matters listed in section 7.1.4 are a force majeure event unless they actually satisfy the definition of "force majeure" under the Code. Further, Synergy considers WP's proposed addition of "any other government energy reforms" is so wide in its potential coverage it counteracts the point of WP's proposal at section 7.1.4. The point of section 7.1.4 should be to clarify areas of potential doubt by giving examples of matters which may be "force majeure" if they satisfy the definition of "force majeure" under the Code. Clearly, citing "any" government energy reforms as an example provides little clarification, given the potentially very wide scope of its coverage (subject to the overriding requirement to satisfy the definition of "force majeure" under the Code).

Considerations of the ERA

1656. Section 6.6 of the Access Code allows target revenue to be adjusted for unforeseen events if:

- During AA3, Western Power incurred capital or operating costs because of a force majeure event.
- Western Power was unable to (or is unlikely to be able to) recover some or all of the costs ("unrecovered costs") under its insurance policies.
- At the time of the force majeure event, Western Power had insurance to the standard of a reasonable and prudent person.

1657. The unrecovered costs that can be added to target revenue do not have to be equal to the amount of unrecovered costs (section 6.7 of the Access Code).

1658. Target revenue must not be adjusted by any amount to the extent that the amount exceeds the costs that would have been incurred by a service provider efficiently minimising costs (section 6.8 of the Access Code).

1659. In its draft decision, the ERA considered Western Power's proposal and the submissions from interested parties and agreed it was consistent with the requirements of the Access Code that Western Power should be able to recover capital and/or operating costs incurred because of a force majeure event. However, the ERA agreed with Alinta and Synergy that the term *"any other government energy reforms"* was very broad and could include both small and large reforms. The broad nature of this term serves little purpose and creates confusion as to what may or may not be a force majeure event.

1660. In any case, in its draft decision the ERA found section 7.1.4 of the access arrangement was unnecessary given the definition of force majeure included in the access arrangement was the same definition used in the Access Code:

> **"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.

1661. Any claimed force majeure event would need to be properly assessed to ensure it met the definition of force majeure before making any adjustments to target revenue. Section 7.1.1 of the access arrangement provides for such an assessment by requiring Western Power to provide, as part of its proposed revisions for the next access arrangement period, a report to the ERA which sets out:

- A description of the nature of the force majeure event.
- A description of the insurance cover that Western Power had in place at the time of the force majeure event.
- The unrecovered costs borne (or an estimate of the unrecovered costs likely to be borne) by Western Power during the access arrangement period as a result of the force majeure event.

1662. Section 6.8 of the Access Code does not allow target revenue to be adjusted by any amount to the extent that the amount exceeds the costs that would have been incurred by a service provider efficiently minimising costs. In its draft decision, the ERA considered the onus to demonstrate efficient costs should be on the service provider, and in the case of Western Power, the demonstration of efficient costs should form part of the report provided under section 7.1.1 of its access arrangement.

1663. The ERA's draft decision required the following amendments to Western Power's proposal.

Draft Decision 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.

Draft Decision Amendment 27

Section 7.1.4 of the proposed revised access arrangement must be deleted.

1664. In its revised proposal, Western Power has accepted required amendments 26 and 27. It has added clause 7.1.1(d) to state that the report required under clause 7.1.1 will include a demonstration that the unrecovered costs do not exceed the level that would have been incurred by a service provider efficiently minimising costs and has deleted clause 7.1.4.

1665. No submissions from interested parties were received on the draft decision.

1666. The ERA is satisfied that draft decision amendments 26 and 27 have been complied with.

Technical Rules

1667. Western Power proposed amending section 7.2.1 of the access arrangement so that it need only report on amendments to the Technical Rules that result in a material change in costs, rather than being required to report on every single amendment.

7.2.1 If ~~the~~amendments to the technical rules ~~are amended~~result in a material cost impact during this access arrangement period, 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 and timing of the impact of the technical rule change on Western Power's non-capital costs and new facilities investment for this access arrangement period; and

b) the costs (or cost savings) incurred, or an estimate of the costs (or cost savings) likely to be incurred by Western Power as a result of that technical rule change.

Submissions on Western Power's initial proposal

1668. Western Power's proposed amendment created confusion, as some stakeholders interpreted it to mean Western Power could make changes to the Technical Rules without public notification if it considers the amendment does not have a material effect on costs.[336]

1669. The current process for approving amendments to the Technical Rules, as set out in chapter 12 of the Access Code, requires all amendments to be approved by the ERA and provides for public consultation on amendments. The proposed amendment, if approved, would not remove the requirement for Western Power to submit Technical Rule amendments to the ERA for approval.

1670. Kleenheat's submission on Western Power's initial proposal raised concerns regarding the process for approving Technical Rule amendments.[337]

> Kleenheat has concern about the Technical Rules governance and with approval and oversight by Western Power itself, Kleenheat would consider that an independent oversight body would be more appropriate.
>
> Kleenheat considers the lack of independent oversight over the Technical Rules to be a concern at a time when non-network solutions and fringe of grid solutions are becoming more prevalent by evolving on from the traditional distributed model of retailers and network operator, and as such the governance and framework should also become more robust and modernised by removing such governance oversight from the network operator whom enforces the Technical Rules. It is noted that the recent energy market reforms to governance and separation of the rule change function were implemented due to a perceived conflict of interest in the governance of market operations and the rule change body.
>
> A rule change panel should be implemented for independent oversight, with the potential to incorporate this responsibility into the existing Rule Change Panel under the Economic Regulation Authority's remit.

1671. AGL and Synergy expressed concerns about the proposed amendment.

- AGL highlighted that the cumulative effect of changes to multiple rules could be material even if the individual changes had no material effect. It suggested "some sort of mechanism be put in place to review the changes holistically."[338]
- Synergy pointed out that the Access Code does not expressly allow for materiality thresholds:[339]

> … sections 6.9 to 6.12 of the Code do not expressly allow for any such materiality threshold, nor does WP indicate how or at what level a cost will be determined to be "material". There is a risk if WP is permitted to set the "materiality" bar as it determines,

[336] See, for example, Mr Stephen Davidson's submission (Submission 1, Issue 15).

[337] Kleenheat Submission, p. 5.

[338] AGL submission, p. 5.

[339] Synergy *AA4 submission No. 5, Western Power's proposed price control mechanisms*, 11 December 2017, p. 25.

> it may give rise to unintended consequences such as the pass-through into target revenue of cost reductions resulting from a change in the technical rules. For example, by labelling a cost reduction resulting from a change in the technical rules as not "material", WP could prevent the cost reduction being passed on to users (and ultimately customers) even though the cost reduction may in reality be significant (either alone or grouped with similar cost reductions). Synergy submits if this proposed amendment is to be approved the Authority will also need to include safeguards (e.g. an objective definition for assessment of "materiality" and appropriate oversight by the Authority to ensure it is being complied with).

Considerations of the ERA

1672. In the draft decision the ERA found that Western Power's proposed amendment to only report on "material" amendments was not consistent with the Access Code requirements. The requirements set out in section 6.9 of the Access Code apply to *any* Technical Rule amendments and do not distinguish between "material" and "immaterial" adjustments.

1673. When proposing Technical Rule amendments to the ERA for approval, Western Power must undertake a comprehensive assessment to demonstrate it meets the objectives for Technical Rules as set out in chapter 12 of the Access Code and the Access Code objectives. It is unlikely Western Power would propose amendments without also considering the effect on its costs. 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.

1674. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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.

1675. In its revised proposal, Western Power has accepted the required amendment and removed its proposed amendments so that clause 7.2.1 is identical to the current access arrangement.

1676. In a submission in response to the draft decision, Mr Davidson suggested the required amendment should expressly qualify any discretion Western Power has under the Technical Rules (and under other regulation/legislation) by requiring it to protect the interests of small users when conducting business on the basis that this would better meet the Code objectives. The Code objective is only relevant to matters dealt with under the Access Code and does not apply generally to other regulation or legislation. Further, draft decision amendment 28 relates to when an adjustment may be made to the target revenue for technical rule changes. It is not open to the ERA to require a further amendment on the basis that it would better meet the Code objectives if Western Power's revised proposal meets the requirements of Chapter 6 and the Code objective, which it does. In any event, the ERA is not convinced that Mr Davidson's amendment is necessary or better achieves the Code objective.

1677. The ERA is satisfied Western Power has complied with draft decision required amendment 28.

Investment adjustment mechanism

1678. The investment adjustment mechanism allows for the carryover from one access arrangement period to the next period of costs or benefits arising from differences in forecast and actual capital costs. The mechanism currently applies to the following classes of capital expenditure:

- connecting new generation capacity
- connecting new loads
- augmentation of the network to provide covered services
- augmentation under the Rural Power Improvement Program and State Underground Power Program
- distribution wood pole management.

1679. Western Power proposed amending the categories to:

- remove distribution wood pole management
- remove the Rural Power Improvement Program
- include provision of metering installations on the distribution system from 1 July 2017.

Submissions on Western Power's initial proposal

1680. CdL Advisory did not support the inclusion of metering in the investment adjustment mechanism because advanced metering infrastructure:

> … delivers efficiencies in terms of meter reading, re-energisation, replacement and refurbishment of meters. These are not factors outside WP control such as demand for energy and the relationship between the new metering technology and new tariff regime.

1681. Although not directly relevant to the form of the investment adjustment mechanism for AA4, Synergy and Kleenheat raised concerns that under-expenditure on metering during AA3 should be adjusted in the AA4 target revenue. Kleenheat wanted to:

> …understand whether the revenue approved by the ERA for advanced metering infrastructure from Western Power's previous Access Arrangement (AA3) (in the order of $91 million) will be carried over to AA4 … as this approved capital expenditure was not spent during AA3 but the AA3 tariffs were set based on the expenditure of this capital. It is our understanding that Western Power has not confirmed that this will occur under AA4. It is understood that the Access Code provides for the ERA to account for the target revenue "true up" between AA3 and AA4.

1682. For AA4, Synergy recommended replacing the investment adjustment mechanism with a capital expenditure incentive scheme. Synergy considered the investment adjustment mechanism limited Western Power's incentive to achieve capital expenditure efficiencies, which increased the risk of over-investment in the network and higher prices in the future.

1683. Synergy also considered the interaction between the investment adjustment mechanism and gain sharing mechanism may distort decisions about whether to undertake capital or operating expenditure which may lead to inefficient outcomes. It also considered the interaction between the service standard adjustment mechanism and the investment adjustment mechanism may provide incentives for Western Power to over invest in the network to achieve higher service performance and receive both cost recovery through the investment adjustment mechanism and an incentive payment under the service standard adjustment mechanism.

1684. Synergy did not support adding metering to the investment adjustment mechanism and submitted the ERA should ensure metering expenditure was subject to a strict regulatory assessment through other mechanisms. It stated:[340]

> Remove distribution wood pole management – In AA3, the Authority stated wood pole replacement should be removed from the IAM once WP has satisfied its obligations under the Energy Safety Order 01-2009. WP notes these obligations have now been satisfied and so is proposing to remove wood pole management in line with the Authority's intention. Synergy supports this change to the IAM.
>
> Remove the RPIP – WP notes it has not undertaken any work in the RPIP since AA2and is not proposing to undertake RPIP work in AA4. Synergy supports this change to the IAM.
>
> Include the provision of metering installations on the distribution network – Synergy opposes the inclusion of this category of expenditure in the IAM. As discussed further in Section 9 of this submission below, there are currently no competitive or regulatory oversights on WP to ensure investment in SMI occurs prudently and efficiently. Inclusion of SMI in the IAM means WP will recover any overspends on advanced meters in subsequent regulatory periods, increasing the risk WP will over invest in its meters and further limits an efficient roll-out of SMI in the SWIS. Synergy submits the Authority should remove SMI from the IAM or, in the alternative, ensure that SMI expenditure is subject to strict regulatory assessment through other mechanisms (e.g. the regulatory test) to ensure it occurs in a manner that is consistent with the long-term interests of consumers.
>
> More generally, Synergy submits the IAM limits the incentive for WP to pursue capex efficiencies. This is because WP will not be rewarded under the IAM, or any other mechanism in AA4, for efficiently reducing its actual capex to below forecast levels. Equally, WP will face little penalty for overspending its capex allowance, since it will be entitled to recover any revenue difference in the next access period (provided any overspend satisfies the NFIT).
>
> These outcomes may contribute to a lack of capex discipline by WP. It reduces the incentive to identify or pursue capex efficiencies on WP's network and may also increase the risk of over-investing the network. This may, in turn, contribute to higher network investment in the future than if WP was subject to sufficient incentives to reduce capex and commensurately higher network tariffs, to the detriment of the long-term interests of consumers.
>
> In addition, the joint operation of the IAM and the GSM may distort decisions about whether to undertake capex or opex. As noted above, the GSM creates an incentive for WP to reduce its opex below the EIBs. The IAM, on the other hand, provides little incentive for WP to perform better than its capex allowance. It follows the incentives WP faces in relation to its opex differ significantly from the incentives it faces with respect to its capex.
>
> This difference has the potential to impact expenditure decisions and may lead to WP reclassifying costs between capex and opex to achieve artificial benefits. For instance, WP may inefficiently capitalise opex to reduce its actual opex spend (leading to a benefit under the GSM)and recover any overspent capex through the IAM. Synergy submits this outcome is inconsistent with the Code objective, including because it does not promote efficient investment in networks and network services in Western Australia.

[340] Synergy *AA4 submission No. 5, Western Power's proposed price control mechanisms*, 11 December 2017, p. 74.

1685. In its submission on Western Power's initial proposal, Synergy submitted the following views on the capital expenditure sharing scheme (CESS):[341]

> The CESS, that ensures the incentive to pursue capex efficiencies is the same in each year of the regulatory period by allowing networks to retain the financial element of any underspend (the return on capital) for a fixed period of 5 years irrespective of the year in which the underspend occurs. Consumers will then benefit at the end of this period when the RAB is rolled forward to a lower amount than if the full amount of capex had been spent, leading to lower network prices in the future. The CESS also plays a critical role in balancing incentives between opex and capex. That is, equal incentive rates between the EBSS and the CESS address the trade-off between capex and opex and remove the incentive for networks to inefficiently capitalise expenditure.

1686. Synergy recommended replacing the current investment adjustment mechanism with a capital expenditure incentive scheme which had:

- No ex-post adjustment to target revenue in the next access period to account for differences between forecast and actual capital expenditure in the current period, provided the differences are shown to be economically efficient (for example, Western Power's target revenue could be adjusted ex-post where forecast capex for a particular project was not used for the project because the project was not carried out).
- The provision of continuous and sustained incentives for Western Power to pursue capital expenditure efficiencies, ensuring these incentives are equivalent to the incentives Western Power faces under the gain sharing mechanism.

Considerations of the ERA

1687. The Access Code requires the inclusion of an investment adjustment mechanism for access arrangements with a price control based on a service provider's approved total costs, which is the case for Western Power.

1688. The concerns Synergy raised about interactions with the gain sharing mechanism and service standard mechanism can be addressed through the ex-post review of all expenditure.

1689. The inclusion of 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). Higher than forecast expenditure can only be recovered to the extent it is demonstrated to be efficient.

1690. Wood pole expenditure was added to the investment adjustment mechanism for AA3. At the time of the AA3 final decision, the ERA was aware the investment needs for wood pole management might change as Western Power developed its understanding of what was required, including agreeing methods for testing the wood poles with EnergySafety. To ensure Western Power had incentives to resolve these issues in a timely and efficient manner, the ERA decided to include expenditure for distribution wood pole management in the investment adjustment mechanism. This was to enable expenditure higher than forecast to be recovered,

[341] Synergy *AA4 submission No. 5 Western Power's proposed price control mechanisms*, 11 December 2017, p. 75.

to the extent that it was demonstrated to be efficient expenditure, and provide Western Power with a return on that investment from the date it was incurred.

1691. The inclusion of wood poles in the investment adjustment mechanism reflected the circumstances at the time of the AA3 review and was not proposed as a permanent measure. As the requirements for wood pole management have now been resolved, the ERA determined in the draft decision that it is no longer necessary or appropriate to include wood pole expenditure in the investment adjustment mechanism.

1692. In the draft decision, the ERA accepted Western Power's proposal to remove the rural power improvement program from the investment adjustment mechanism as the program is no longer used.

1693. In the draft decision, the ERA determined that including metering expenditure in the investment adjustment mechanism was not consistent with the Code objective and did not provide appropriate incentives for efficient metering expenditure.

1694. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision Required Amendment 29

Metering expenditure must be removed from the Investment Adjustment Mechanism

1695. In its revised proposal, Western Power has not accepted draft decision required amendment 29. It submits that it proposed the inclusion of distribution metering capital expenditure in the investment adjustment mechanism as it would:[342]

- 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.

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.

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.

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,

[342] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 179-180.

Western Power and its customers will be kept financially neutral under our proposed approach.

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).*

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.

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.

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.

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.

1696. Consistent with previous access arrangements, Western Power's proposed metering capital expenditure includes meters for new properties, meters that require replacement as they are no longer compliant with the metering standards and replacements of meter requested by retailers or customers. Western Power requires a contribution from retailers or customers for requested replacement meters. Western Power proposed additional expenditure to install advanced metering communication infrastructure but, as set out in the section on the forecast regulated capital base for AA4, the ERA has not approved this expenditure.

1697. Western Power submits its metering program, as with all other customer driven work, is subject to a degree of uncertainty and that this uncertainty is heightened when new services are introduced such as advanced metering. It considers the inclusion of metering under the investment adjustment mechanism will allow it to accommodate this level of uncertainty as, if retailer or customer-driven meter replacements are greater than forecast it will be able to recover the additional expenditure, and if volumes are lower than forecast it will be able to give the money back. It considers including the expenditure in the investment adjustment mechanism will keep Western Power and its customers financially neutral under either scenario.

1698. As set out in the draft decision, including metering expenditure in the investment adjustment mechanism would not promote efficient investment in metering. This is because it would limit the incentive to pursue capital expenditure efficiencies (as Western Power does not retain the benefit of reduced capital expenditure for items included in the investment adjustment mechanism) and would not discourage Western Power from overspending its capital expenditure allowance, as it would be able to recover it in the next access arrangement period (subject to demonstrating it is efficient). This is not consistent with the Access Code objective

1699. Western Power refers to uncertainty about the level of retailer or customer driven meter requests. The ERA agrees there is a level of uncertainty regarding this, however Western Power charges a contribution for replacement meters requested by retailers or customers. Providing the contribution is set to match the actual metering costs, Western Power's position is financially neutral regardless of the volumes requested. Customers receiving the replacement meter should pay the actual cost so they are not cross subsidised by other customers.

1700. Consequently, the ERA maintains its requirement that metering expenditure must be removed from the investment adjustment mechanism

Required Amendment 36

Metering expenditure must be removed from the investment adjustment mechanism.

Gain sharing mechanism

1701. Western Power will retain the benefit of any savings on operating expenditure, compared with the forecast operating expenditure approved, during the AA4 period. If actual expenditure is higher than forecast, Western Power will have to fund the additional expenditure during the AA4 period. However, this means savings (or additional costs) during the first year are retained for five years, while savings achieved during the final year are retained for only one year.

1702. Western Power's gain sharing mechanism allows it to retain benefits for five years from when the efficiency was achieved (that is, the year it makes the saving plus five years of carry over) regardless of which year the efficiency is first made. The gain sharing mechanism is intended to ensure that Western Power has equal incentives to pursue efficiency throughout the access arrangement period.

1703. The access arrangement must include a gain sharing mechanism[343] unless the ERA determines it is not necessary to achieve the objective in section 6.4(a)(ii) of the Access Code. The objective of 6.4(a)(ii) is to give the service provider an opportunity to earn revenue to reward it for efficiency gains and innovation beyond those assumed in the access arrangement.

1704. The gain sharing mechanism must:[344]

- 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

[343] As required under section 6.20 of the Access Code.

[344] As set out in section 6.21 of the Access Code.

(for example, a service provider should not have an artificial incentive to defer an innovation until after an access arrangement review).

1705. The access arrangement must include efficiency and innovation benchmarks[345] that will be used at the next access arrangement review to determine any above-benchmark surplus under the gain sharing mechanism. The efficiency and innovation benchmarks must:[346]

- Be sufficiently detailed and complete to permit the ERA to determine the above benchmark surplus at the next access arrangement review.
- Provide an objective standard for assessing Western Power's efficiency and innovation during the access arrangement period.
- Be reasonable.

1706. The Access Code specifies that an above-benchmark surplus does not exist to the extent that a service provider achieved efficiency gains or innovation in excess of the benchmarks during the previous access arrangement period by failing to meet the service standard benchmarks set out in the access arrangement.[347]

1707. Western Power proposed to amend the gain sharing mechanism to:

- Apply the mechanism separately to the transmission and distribution services rather than a single mechanism as is currently the case.
- Update the network growth escalation assumptions and uncontrollable cost input values to reflect latest forecasts.

1708. The ERA has considered matters relevant to Western Power's proposed gain sharing mechanism in the following order:

- requirements for a gain sharing mechanism
- limitations of the current mechanism
- Western Power's proposal to set separate benchmarks for transmission and distribution
- the efficiency and innovation benchmarks.

Requirements for a gain sharing mechanism

1709. Stakeholder submissions on Western Power's initial proposal noted benefits the gain sharing mechanism provides to consumers.

1710. Energy Networks Australia submitted:

> Once the regulator has set the revenue allowances, businesses have an incentive to improve efficiency to outperform regulatory benchmarks. If a business is successful in spending less than the efficient expenditure assumed by the regulator, the businesses may keep these savings for a time. However, the short-term rewards that businesses obtain from making such savings are ultimately translated into long-term benefits to consumers. This is because the businesses reveal the true scope for efficiencies to

[345] As required under section 5.1(j) of the Access Code.

[346] As set out in section 5.26 of the Access Code.

[347] As set out in section 6.26 of the Access Code.

the regulator. In subsequent periods, the regulator can use this information to set more challenging targets, thereby passing on savings permanently to customers.

1711. Synergy supported the use of a gain sharing mechanism to incentivise Western Power to pursue operating expenditure efficiencies. It noted that even though Western Power kept the benefit of any efficiencies earned during the access arrangement period, its incentive to reduce operating expenditure decreased as it approached the end of the access arrangement period. It considered the gain sharing mechanism had an important role to ensure Western Power had a constant and continuous incentive to achieve efficiency gains in operating expenditure, regardless of the timing of those efficiencies.

1712. Perth Energy supported the principle that gain sharing could exist, provided that the efficiencies gained by Western Power did not come at the expense of lower service to customers.

1713. The access arrangement must include a gain sharing mechanism unless the ERA determines it is not necessary to achieve the objective in section 6.4(a)(ii) of the Access Code. The objective of 6.4(a)(ii) is to give the service provider an opportunity to earn revenue to reward it for efficiency gains and innovation beyond those assumed in the access arrangement. Consequently, in the draft decision the ERA determined the gain sharing mechanism was required to be included in Western Power's access arrangement.

Limitations of the current mechanism

1714. Synergy's and Bluewater's submissions on Western Power's initial proposal raised concerns regarding the current mechanism.

1715. Synergy noted the current mechanism was not symmetrical. Although Western Power retains the benefits of savings for five years after the year they are made, if it spends more than forecast costs, it does not result in Western Power having to pay a penalty in the next access arrangement period.[348] Synergy submitted this was inconsistent with the approach adopted by the Australian Energy Regulator, which carried forward all efficiency gains and losses. Synergy considered this constraint should be removed to make the mechanism symmetrical.

1716. The ERA considered making the gain sharing mechanism symmetrical as proposed by Synergy. This approach has been adopted by the Australian Energy Regulator. The ERA considered 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.

1717. The ERA's draft decision required section 7.4.8[349] of the proposed revised access arrangement to be deleted.

Draft Decision Required Amendment 30

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[348] Clause 7.4.5 of the current access arrangement.

[349] Clause 7.4.8 of the proposed revisions states: In any year where the amount of an adjustment to target revenue for the transmission system or the distribution system determined under section 7.4.7 of this access arrangement is a negative value, the amount of the adjustment to target revenue for the transmission system or the distribution system respectively in that year is zero.

Section 7.4.8 of the proposed revised access arrangement must be deleted.

Western Power's revised proposal

1718. In its revised proposal, Western Power has not accepted the required amendment.[350] It submits:

> 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.
>
> 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.
>
> 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.
>
> 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]*
>
> 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….*
>
> 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*.
>
> 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]*
>
> 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.
>
> 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*

[350] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 181-183.

> *between users and Western Power as Western Power would be subject to symmetrical rewards and penalties.*

However, this omits important aspects of section 6.21(a) of the Access Code (which are underlined below):

> *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.*

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.

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.

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.

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.

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.

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.

Considerations of the ERA

1719. In the draft decision the ERA determined the gain share mechanism should be symmetrical to be consistent with the Access Code requirements to achieve an equitable allocation of efficiencies between users and Western Power by making Western Power subject to symmetrical rewards and penalties.

1720. In its revised proposal, Western Power submits that the Access Code prohibits the gain share mechanism from producing a result that would cause target revenue in the next access arrangement to reduce.

1721. The ERA notes the Access Code wording does not expressly prohibit negative amounts to be added to target revenue at the next period. and conceptually the inability to add negative amounts to target revenue would give an inaccurate (inflated) result.

1722. An asymmetrical mechanism is also inconsistent with the Access Code objective of promoting efficient investment in and operation of the network as Western Power only receives rewards for under-expenditure and no penalties for over-expenditure.

1723. Western Power also submits the reasons the ERA has given for requiring the amendment omits an aspect of section 6.21(a) of the Access Code. Specifically, the ERA's draft decision referred to achieving an "equitable allocation of efficiencies between users and Western Power" whereas section 6.21(a) refers to "achieving an equitable allocation over time between users and the service provider".

> 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 the efficiency gains.

1724. The ERA considers the end result of achieving an equitable allocation of efficiencies over time between users and the service provider is an equitable allocation of efficiencies between users and the service provider. As the current mechanism is not symmetrical, efficiencies are not being allocated equitably over time as not all over-expenditure is being offset against under-expenditure.

1725. Western Power notes the ERA's draft decision to remove the financial rewards and penalties under the service standard adjustment mechanism. It considers that, without the service standard adjustment mechanism, there is an incentive for it to let service standards deteriorate and that the incentive to do this would become even stronger if there was a penalty under the gain share mechanism for overspending operating expenditure.

1726. The ERA's final decision has reinstated the financial rewards and penalties under the service standard adjustment mechanism.

1727. Western Power also refers to the ERA's draft decision not to approve its in-period approval of D-factor projects. Western Power considers these changes were necessary to improve certainty that it would be able to recover the costs of non-network solutions. It considers that facing penalties for failing to meet service standard benchmarks (from foregoing any reward under the gain share mechanism) and penalties for overspending operating expenditure (if the gain share mechanism is symmetrical) increases the incentive for it to reduce its operating expenditure to no more than the operating expenditure required to meet the service standard benchmarks.

1728. As set out in the ERA's draft decision and again in the final decision on the D-factor scheme, the Access Code includes sufficient provisions to enable Western Power to lodge an application during the access arrangement period for a determination on a D-factor project. There should be no barrier to Western Power adopting a non-network solution if it is more efficient than a network solution.

1729. In any case, D-factor costs are specifically excluded from the benchmarks and actual operating expenditure as set out under section 7.4.3 of the proposed revised access arrangement.

1730. Western Power contends its proposed gain share mechanism is equitable. Although the mechanism itself is not symmetrical, Western Power submits the calculation of the above benchmark surplus includes negative amounts and that these overspends offset gain share mechanism rewards in other years therefore acting as a form of penalty.

1731. The ERA considers the current gain share mechanism partially recognises both under and over expenditure. Removing the current constraint, (as set out in section 7.4.8 of the proposed revised access arrangement) that if the total gain share mechanism adjustment for a particular year results in a negative value it will be set at zero, would result in the timing of the total adjustment being allocated equitably over time between users and Western Power.

1732. However, the ERA recognises a plain English reading of the Code is that only positive adjustments can be made to target revenue at the next access arrangement review. Consequently, the ERA is not able to require Western Power to make the mechanism symmetrical by removing section 7.4.8 of the proposed access arrangement, even though it considers the current mechanism is not consistent with the Code objective.

Carry-over period for efficiencies

1733. Bluewaters and the ERA's technical consultant raised concerns regarding the timing of savings and how long they were retained by Western Power under the current gain sharing mechanism.

1734. Bluewaters noted a feature of the current design was that network users did not receive the benefit of any savings made by Western Power until five years after the saving was made. It submitted:

> … Western Power will keep 100% of its saving for five years. This may be an expensive option.
>
> For achieving the efficiency gain, Bluewaters questions if there is another way to provide the same incentive to Western Power that: (a) is less expensive; and (b) enables network users to realise the benefits quicker.
>
> A possible alternative is to design a mechanism that: (a) splits the saving on a 50/50 basis between Western Power and network users (b) pays the benefit to network users (in the form of reduced tariff) in financial year following the financial year which the saving was made.

1735. The ERA's technical consultant GHD considered Western Power did not demonstrate ongoing continuous improvement in its management of its operating expenditure during AA3, and noted the step reduction in expenditure in the final year of AA3 coincided with a significant reduction in staff numbers. GHD considered the current gain sharing mechanism did not provide sufficient incentive for Western Power to capture these efficiencies earlier in the AA3 period and resulted in a benefit to Western Power: It considered the structure of the mechanism was much less generous to a service provider undertaking a continuous improvement program than one that applies a step improvement late in an access arrangement period.

1736. As outlined above, the Access Code requires the gain sharing mechanism to:

- Achieve an equitable allocation of any efficiencies over time between users and the service provider.
- 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.

1737. The current gain sharing mechanism allows Western Power to retain the benefit of any savings for six years – that is, the year the saving is made plus five years of carryover (through the remainder of the access arrangement period and the gain share mechanism).

1738. Reducing the period that savings are carried over to four years, would result in Western Power keeping the benefit for five years (that is, the year the saving is made plus four years of carryover through the remainder of the access arrangement period and gain share mechanism). As the access arrangement period is five years, reducing the carry-over period would still ensure Western Power is neutral as to the timing of savings during the access arrangement period. It would also enable users to realise the benefits sooner.

1739. In the draft decision, the ERA determined that reducing the period to four years would achieve a more equitable allocation of efficiencies between users and Western Power while still ensuring the incentives for Western Power to achieve efficiencies are equal throughout the access arrangement period.

1740. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

1741. In its revised proposal Western Power has not accepted the required amendment and submits the following.[351]

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.

The ERA requires amendments to the access arrangement to reduce the retention of GSM benefits from five years to four years. This appears 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.

[351] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 183-187.

Sharing benefits between Western Power and its customers

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.

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.*

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.*

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

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.

- the carry-over period should align to the length of the regulatory period

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.

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.

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.

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.

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.

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.

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.

Ongoing continuous improvement in managing opex

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.}*

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.

Including negative above-benchmark surplus amounts accounts for any reduction in costs that is not sustained.

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.

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.

Despite these incentive mechanisms, GHD considers we have not demonstrated ongoing continuous improvement in our management of opex during AA3. 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.

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.[352]

Consistency with the Access Code

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.

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.

In its own 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.

For these reasons we do not accept the ERA's required amendment.

1742. In its response to the draft decision, Western Power notes the ERA's required amendment appears to be on the basis that:

- Stakeholder submissions indicated that a higher proportion of our savings should be passed on to customers.
- The Authority's technical consultant, GHD, considers Western Power has not demonstrated ongoing continuous improvement in its management of operating expenditure during AA3.

1743. The ERA has considered stakeholder submissions and GHD's views. However, in making its assessment of the gain share mechanism, the ERA's considerations have been based on the requirements of the Access Code for how efficiencies should be shared. The ERA acknowledges the management of operating expenditure is the

[352] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 186.

responsibility of Western Power and Western Power is free to achieve savings in the manner it considers optimal.

1744. Western Power refers to the period savings are retained under the gainsharing mechanism as being consistent with the mechanism approved by the ERA for AA3 and consistent with the Efficiency Benefit Sharing Scheme under the national electricity framework.

1745. The ERA did not specifically consider the period over which efficiencies should be retained during the AA3 review as Western Power did not propose amending the AA2 provisions and the matter was not raised in submissions. No gain share mechanism was earned during AA2 as Western Power failed at least one service standard benchmark in each year.

1746. The Efficiency Benefit Sharing Scheme under the national electricity framework provides useful background but it must be remembered that Western Power's gain sharing mechanism is assessed under the requirements of the Access Code, not the national electricity framework. The Efficiency Benefit Sharing Scheme forms part of the national electricity framework's overall approach for assessing and setting expenditure allowances which is different from the requirements specified in the Access Code.

1747. In determining the period that efficiencies should be retained by Western Power, the most relevant of the Access Code requirements are the objectives specified in section 6.21(c) and 6.21(a) of the Access Code.

1748. The objective specified in 6.21(c) is:

> giving 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.

1749. In the absence of a gain sharing mechanism, Western Power would only retain the benefits of any efficiencies during the access arrangement period. Assuming a five year access arrangement period, this means efficiencies achieved in the first year and sustained for the whole access arrangement period would be retained for five years in total. New efficiencies achieved in the final year of the access arrangement period would only be retained by Western Power for one year. Consequently, the minimum carry-over period (that is the number of years following the year the efficiency is first made) required to ensure Western Power is neutral about the year in which it achieves an efficiency during an access arrangement period, is four years.

1750. A carry over period longer than four years would still meet the requirements of section 6.21(c). However, the objective specified in 6.21(a) refers to the allocation of innovation and efficiency gains over time between users and the service provider:

> achieving an equitable allocation over time between users and the service provider …

1751. Under a gain share mechanism with a carry-over period of four years, the benefits from efficiencies are passed to users five years after they are first achieved by Western Power. Western Power has calculated this is the equivalent to a sharing ratio of 20:80 between Western Power and its customers in perpetuity. The sharing ratio under a five-year carry-over period, where the benefits from efficiencies are passed to users six years after they are first achieved by Western Power, has been calculated by the AER as 30:70.

1752. Western Power submits that sharing schemes such as the gain sharing mechanism are designed to provide a fair sharing of benefits between network users and network service providers. It considers the 30:70 sharing of benefits coupled with the various offsetting incentive arrangements under the investment adjustment mechanism and service standard adjustment mechanism meets the Access Code objective and section 6.21(a) of the Access Code.

1753. Western Power also considers that if the power of the gain share mechanism is diminished, for example by reducing the time period over which the benefits are retained, then the network service provider may be given a perverse incentive to increase expenditure during what would be revealed as its efficient base year.

1754. As explained above, for a five-year access arrangement period, a carry-over period of four years is sufficient to ensure the incentives for achieving efficiencies are equal for each year of the access arrangement, including the final year. Increasing the carry over period would increase the period Western Power retains the benefit from those savings and delay the passing on of those savings to users but would not reduce the incentive for making efficiencies in the final year of the access arrangement compared with the earlier years of the access arrangement.

1755. The ERA considers a four-year carry-over period would be preferable for consumers as it would pass through efficiencies sooner. However, Western Power's proposed five year carry-over period is not inconsistent with the requirements of sections 6.21(a) and 6.21(c) of the Access Code or the Code objective. Consequently the ERA cannot require it to amend the period.

Interrelationship with service standards

1756. As noted in Perth Energy's submission, efficiency gains by Western Power should not come at the expense of a lower standard of service to customers. Synergy also noted the trade-off between achieving cost efficiencies and maintaining service standards needs to be considered.

1757. The Access Code specifies that an above-benchmark surplus does not exist to the extent that a service provider achieves efficiency gains or innovation in excess of the benchmarks during the previous access arrangement period by failing to meet the service standard benchmarks set out in the access arrangement.

1758. The current gain sharing mechanism specifies that Western Power must achieve all of its service standard benchmarks in a particular year to be eligible for any gain share surplus in that year.

1759. The current approach 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.

1760. In the draft decision, the ERA considered these unintended consequences could be overcome by calculating the gain share for the entire period without adjustments for service standard benchmark failures. An adjustment could then be applied to the total gain share for the access arrangement period based on the proportion of years that service standard benchmarks were not achieved.

1761. The ERA's draft decision required the following amendment to Western Power's proposal.

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.

1762. In its revised proposal Western Power has not accepted the required amendment and submits the following.[353]

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.

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.

The ERA has developed an alternative approach to link the GSM to the achievement of our SSBs, and requires 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.

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.

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.

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

[353] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p Western Power revised proposal pp. 187-188.

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.

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.

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.

For these reasons we do not accept the ERA's proposed amendment.

1763. The ERA does not agree with Western Power's submission that the inclusion of negative amounts in the calculation of the gain share adjustment value ensures that Western Power is not incentivised to overspend operating expenditure in a year where it does not meet all of its service standard benchmarks. In fact, this is one of the concerns the ERA has because increasing expenditure in a year where there has been a service standard benchmark failure can result in the following year's incremental saving appearing higher than it otherwise would.

1764. For this reason, the ERA considers the current gain share mechanism does not meet the requirements of section 6.21(a) or 6.21(c) of the Access Code as it does not result in a neutral effect on the timing of efficiencies or an equitable allocation over time between users and Western Power.

1765. Western Power submits the required amendment is inconsistent with the Access Code because it does not use annual amounts. Contrary to Western Power's view, sections 6.21 to 6.28 of the Access Code do not specify that the gain share mechanism must be specified or calculated on an annual basis.

1766. Adequate information was provided in the draft decision regarding the adjustment required. As set out in the draft decision, the gain share should be calculated for the entire period without adjustments for service standard benchmark failures. An adjustment for service standard failures over the period can then be calculated based on the proportion of years that service standard benchmarks were not achieved.

1767. For the reasons set out above the ERA final decision requires the following amendment to Western Power's proposal.

Required Amendment 37

Section 7.4.3 of the proposed revised access arrangement must be amended to specify that an adjustment, based on the proportion of years with service standard benchmark failures over the access arrangement period, will be made to the total above-benchmark surplus.

Separate benchmarks for transmission and distribution

1768. The current gain sharing mechanism includes a single efficiency and innovation benchmark covering the total business. For AA4, Western Power proposed to set separate efficiency and innovation benchmarks for the transmission and distribution businesses. Western Power noted the requirement to link the gain sharing mechanism with service standard performance means Western Power foregoes the total reward for efficiency improvements if it does not meet service standard benchmarks for either service.

1769. Western Power considered separate benchmarks would ensure:[354]

- Each workforce is held accountable for its own performance.
- Western Power is provided with an equal incentive to achieve efficiencies in both the distribution and transmission networks.
- The incentive to achieve efficiencies in one network is not weakened by poor service performance in the other network.
- The current ambiguity regarding the appropriate allocation of GSM rewards between distribution and transmission target revenue requirements is removed.

1770. Submissions from Perth Energy, Synergy and Community Electricity on Western Power's initial proposal commented on the gain share mechanism. All raised concerns that adopting separate efficiency and innovation benchmarks could lead to unintended consequences and the potential for gaming.

1771. Synergy was not opposed to separate benchmarks in principle but considered:

> … the ERA must ensure the incentives between the two networks are consistent. Otherwise WP would have an incentive to simultaneously maximise its opex efficiency gains and minimise its losses across both businesses, to achieve the largest net benefit. In contrast, under separate schemes, the large GSM gain on its distribution business would be carried forward in full, while the GSM loss on its transmission business would be capped (since the current GSM does not allow for an absolute reduction in opex). This creates unintended incentives, particularly an incentive to localise all expected efficiency losses in one business. Synergy considers this could be addressed by making the GSM symmetrical in operation between efficiency gains and losses and between the transmission and distribution business.

1772. Perth Energy acknowledged the benefits Western Power put forward for adopting separate benchmarks but had concerns similar to Synergy:

[354] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 107.

> Perth Energy is concerned that by developing GSM benefits in independently within the respective business units of Western Power, there is an incentive for one business unit to act in a manner that maximises their GSM benefits to the detriment of the interests of customers of other business units, and to the Western Power organisation.
>
> If Western Power want to calculate and report GSM benefits by business unit, Perth Energy would propose that it must pass a test that ensures the benefits achieved by the business unit also provided net incremental benefits to the entire organisation prior to it being approved by the ERA. This would stop business units gaining efficiencies at the expense of the other business and potentially at the expense of Western Power as a whole.

1773. Community Electricity considered:

> … the assessment should remain holistic so as prevent gaming through cross-subsidy.

1774. The ERA considered Western Power's proposal to implement separate measures. Although Western Power has separate revenue targets for transmission and distribution, many costs (particularly corporate and indirect costs) are common to both services and are required to be allocated. Setting separate gain share mechanisms could lead to cost transfers between transmission and distribution to maximise rewards.

1775. The gain sharing mechanism is required to be objective, transparent and easy to administer. The ERA considered the additional controls that would be needed to ensure cost transfers did not occur would add significant complexity to the mechanism. The ERA considered the current single measure provides sufficient incentives.

1776. In the draft decision, the ERA determined that setting separate measures would 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.

1777. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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

1778. In its revised proposal, Western Power has not accepted this required amendment and submits the following.[355]

> 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.
>
> 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*

[355] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 189-190.

of the Access Code and the Code objective. The ERA requires Western Power to remove the separate transmission and distribution efficiency and innovation benchmark tables and replace them with a single table.

We highlight that the ERA did not remove the related amendment for this split in section 7.4.2 of the access arrangement.

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.*

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.

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.* 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*. It therefore draws the conclusion that the proposed amendment would be inconsistent with section 6.21 of the Access Code.

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.

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.

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.

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.

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.*

> 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.
>
> 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).
>
> 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.

1779. Western Power highlights the ERA's required amendment did not remove the related amendment for this split in section 7.4.2 of the access arrangement. This was an oversight, the required amendments should also include deletion of Western Power's proposed new section 7.4.2:

> This gain sharing mechanism applies separately to each of:
>
> a) the transmission system; and
>
> b) the distribution system.

1780. Western Power refers to the ERA's AA3 decision to not allow it to combine performance measures for the transmission and distribution network as it would dilute the attribution of performance and obscure priorities for improvement. It submits that its proposal to separate the gain share mechanism recognises the power of incentivising improvement in service performance and efficiencies in each part of the business.

1781. The ERA considers the issues are quite different. In the case of service performance, the performance of transmission and distribution assets can be clearly separated and attributed to the specific assets. In the case of cost efficiencies, as discussed in the draft decision, many costs (particularly corporate and indirect costs) are common to both services and must be allocated on some basis. Attributing efficiencies separately to transmission and distribution is therefore not as clear cut as in the case for service standards.

1782. Western Power submits there are sufficient controls to ensure costs are not transferred between transmission and distribution to maximise rewards. It considers its cost and revenue allocation method, audited regulated financial statements, and pro-forma forecast statements, which it provides to the ERA, include sufficient information on the proposed allocation of costs such that no additional costs are required.

1783. The ERA acknowledges that this information is available but has not been specifically designed to accommodate separate gain share measures for each service. In particular, the cost and revenue allocation method is not approved by the ERA. The ERA is aware changes have been made to the cost and revenue allocation method during AA3 and there is no reason changes will not be made during AA4.

1784. Western Power appears to imply that the ERA's access arrangement information guidelines specifically require a proper allocation between distribution and transmission if the gain share mechanism is split between services. This is not the case. The access arrangement information guideline was prepared in 2010 when there was a single gain share mechanism, and includes only general requirements for details of how the adjustment has been calculated and evidence that a like-for-like comparison has been made between benchmarks and actual costs.

1785. A much more robust cost allocation framework and access arrangement information guideline would be necessary to support separate transmission and distribution gain share mechanisms. The ERA maintains its draft decision that the additional measures required to set separate mechanisms would add unnecessary complexity and, therefore, is inconsistent with the requirements of section 6.21(b) of the Access Code.[356]

Required Amendment 38

Western Power must delete proposed new section 7.4.2 and the following tables from the proposed revised access arrangement:

- Table 32: Efficiency and innovation benchmarks for the transmission system.
- Table 33: Efficiency and innovation benchmarks for the distribution system.

Western Power must include a single table with efficiency and innovation benchmarks for the total business consistent with the ERA's determination of efficient operating costs.

Setting the efficiency and innovation benchmarks

1786. The efficiency and innovation benchmarks for the current gain sharing mechanism are based on the operating expenditure forecasts approved by the ERA in its AA3 decision. Superannuation costs for defined benefit schemes, costs of non-revenue cap services, licence fees, EnergySafety levy and the ERA fees are excluded as these costs are outside Western Power's control.

1787. The forecast operating expenditure for AA3 included forecast network growth and customer growth escalators. These are replaced with the actual growth factors when calculating the above-benchmark surplus at the end of the period. This ensures Western Power will not be rewarded or penalised for variations from forecast operating expenditure that are attributable to differences in the scale factors driving expenditure and that, conversely, customers do not pay more under the gain sharing mechanism because of slower growth.

1788. The forecast network growth escalation assumptions and uncontrollable cost input values Western Power proposed for AA4 were considered in the operating expenditure section.

[356] Section 6.21(b) being objective, transparent, easy to administer and replicable from one access arrangement to the next;

1789. As the ERA did not approve Western Power's proposed operating costs, the Efficiency and Innovation Benchmarks included in section 7.4.11 of the proposed revisions to the access arrangement were be amended to be consistent with the ERA's determination of efficient operating costs set out in the draft decision.

Draft Decision Required Amendment 34

Western Power must amend the efficiency and innovation benchmarks to be consistent with the draft decision on operating expenditure.

1790. In its revised proposal, Western Power accepted draft decision required amendment 34 in principle, but based its efficiency and innovation benchmarks on its proposed operating expenditure.[357]

1791. The ERA has not approved Western Power's proposed operating expenditure for AA4. Consequently, the Efficiency and Innovation Benchmarks included in section 7.4.11 of the proposed revisions to the access arrangement must be amended to be consistent with the ERA's determination of efficient operating costs set out in this final decision.

Required Amendment 39

Western Power must amend the efficiency and innovation benchmarks to be consistent with the final decision on operating expenditure.

[357] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 191-192.

Service standard adjustment mechanism

Access Code requirements

1793. Section 6.30 of the Access Code requires an access arrangement to include a service standard adjustment mechanism.

1794. The service standard adjustment mechanism is defined in section 6.29 as a mechanism detailing how the service provider's performance against the service standard benchmarks during the access arrangement period is to be treated by the regulating authority at the next access arrangement review.

1795. Section 6.31 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.

1796. The Code objective is specified in section 2.1 of the Access Code:

> 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.

1797. Under section 11.6 of the Access Code, before determining whether to impose a civil penalty for non-compliance with service standard benchmarks, and to minimise the likelihood of Western Power being excessively penalised, the ERA must also have regard to:

- any remedies awarded (or likely to be awarded) against the service provider under contracts for services in relation to the act or omission which resulted in the service provider not complying with section 11.1 of the Access Code; and

- the service standard adjustment mechanism,

before determining whether to impose a civil penalty for non-compliance with service standard benchmarks, under section 11.6 of the Access Code, to minimise the likelihood of Western Power being excessively penalised.

Current access arrangement

1798. In the third access arrangement period, the service standard adjustment mechanism comprised:

- Service standard targets, set at the 50th percentile of the probability distribution of best fit to historical performance data.

- Incentive rates (penalties and rewards) determined using estimated values of customer reliability for distribution performance measures, and proxy rates for the value of service for transmission performance measures.

- Individual penalty caps for each performance measure, set at the service standard benchmark level of performance.
- Cumulative reward and penalty caps, set at a percentage variation of the allowable target revenue (revenue-at-risk) for distribution and transmission networks in each year.

1799. The total target revenue adjustment under the service standard adjustment mechanism may be positive (net reward) or negative (net penalty) and is determined for each of the distribution and transmission networks by the following formula:

$$SSAM_N = \sum_t \sum_p (SSD_{p,t} * IR_p)$$

Subject to the revenue-at-risk constraints in each year:

$$RAR_N^- \leq SSAM_{N,t} \leq RAR_N^+$$

Where:

$SSAM_{N,t}$	is the target revenue adjustment for the next access arrangement period on the distribution or transmission network (N) accrued in financial year (t)
$SSD_{p,t}$	is the service standard difference on performance measure (p) in financial year (t)
IR_p	is the incentive rate applicable to performance measure (p), and may be a reward (for outperformance) or penalty (for underperformance)
RAR_N^+	is the upper revenue-at-risk (cumulative reward) cap on the distribution or transmission network (N)
RAR_N^-	is the lower revenue-at-risk (cumulative penalty) cap on the distribution or transmission network (N)

1800. The service standard difference (SSD) is defined in section 7.5.4 of the access arrangement for the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), loss of supply event frequency and average outage duration performance measures as the difference between actual performance and target performance if actual performance is lower than the benchmark performance, or the difference between target performance and benchmark performance if actual performance does not meet benchmark performance:

$$SSD_{p,t} = \begin{cases} SST_p - SSA_{p,t} \text{ } if \text{ } SSA_{p,t} < SSB_p \\ SST_p - SSB_p \text{ } if \text{ } SSA_{p,t} \geq SSB_p \end{cases}$$

where:

$SST_{p,t}$	is service standard target for performance measure (p) in financial year (t)

$SSA_{p,t}$	is the actual service performance on performance measure (p) in financial year (t)
SSB_p	is the service standard benchmark applicable to performance measure (p)

1801. The service standard difference for the call centre performance and circuit availability performance measures, where higher values indicate better performance, is derived as:

$$SSD_{p,t} = \begin{cases} SST_p - SSA_{p,t} \; if \; SSA_{p,t} > SSB_p \\ SST_p - SSB_p \; if \; SSA_{p,t} \leq SSB_p \end{cases}$$

Performance during the third access arrangement period

1802. Western Power achieved a target revenue adjustment under the service standard adjustment mechanism of $250.9 million (real value at 30 June 2017) in the third access arrangement period from service performance on the distribution networks, and $13.4 million from the transmission network, to be applied to target revenue in the fourth access arrangement period (Table 175, below).[358]

1803. The following individual penalty and cumulative reward caps were applied during the third access arrangement period:

- The penalty applied to SAIFI Rural long was capped during 2012/13 and 2013/14 due to actual performance of 4.91 and 4.98 average interruptions not meeting the benchmark level of 4.51.
- The penalty applied to average outage duration was capped in 2015/16 due to actual performance of 1265 system minutes not meeting the benchmark of 886 system minutes.
- The total reward applied to the distribution network was capped at 5.0 per cent of distribution target revenue in 2013/14, 2015/16 and 2016/17.
- The total reward applied to the transmission network was capped at 1.0 per cent of target revenue on the transmission network in 2014/15, 2015/16 and 2016/17.

1804. Service performance outcomes on Western Power's distribution and transmission networks during the third access arrangement period were explained as follows:

- Underground cable failures affected SAIDI and SAIFI performance on the CBD feeder in 2013/14, although overall performance achieved the minimum benchmark performance.[359]
- Ongoing works and vegetation management resulted in consistent out-performance against the service standard targets on the Urban and Rural

[358] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, pp. 227-9, paras. 929, 931, 932.

[359] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 60, para.204.

short feeders, in addition to favourable weather and fewer vehicle and fauna incidents than the previous period.[360,361]

- SAIFI underperformance on the Rural long feeder was attributed to adverse weather conditions, lightning and fauna incidents on exposed overhead assets.[362] A hotspot identification and maintenance program delivered improved reliability performance in the 2015/16 and 2016/17 financial years.[363]

- Call centre performance remained above target throughout the third access arrangement period due to the increasing adoption and availability of alternative communication channels, including social media and the corporate website.[364]

- Transformer failures at Muja affected average outage duration performance on the transmission network in 2015/16.[365]

- A lower than forecast capital works program influenced circuit availability, in addition to the re-scoping or deferment of works under the Business Transformation Project.[366]

1805. Other significant events on the Western Power Network during the third access arrangement period included:

- Completion of a capital works program involving the replacement or reinforcement of more than 270,000 wood poles, and removal of high-risk overhead connections and switchwire from the network.

- Construction of a 200-kilometre transmission line from Pinjar to Eneabba to connect windfarm generators and mining customers to the network.[367]

1806. Western Power also acknowledged that, despite the substantial improvements in overall performance achieved during the third access arrangement period, pockets of the network remained under-serviced:

> Service performance also improved overall during the AA3 period, with the network now providing electricity 99.96 per cent of the time and call centre response times tracking at 91.8 per cent. While there remain pockets of the network that require further

[360] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 61, para.205.

[361] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 62, para.206.

[362] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 63, para.207.

[363] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 64, paras.208-9.

[364] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 69, para.222.

[365] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 64, para.211.

[366] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 68, para.220.

[367] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. xxiii.

investment, reliability of supply is generally good. Further, the business has made improvements to its structure and processes, incurring $1,481 million (17 per cent) less expenditure during AA3 than forecast, and reducing forward-looking costs. This means Western Power ended the AA3 period with a good foundation for starting the AA4 period.[368]

[368] Western Power, Access arrangement information, access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. xxiii.

Table 175 Rewards and penalties applied to service performance on Western Power's distribution and transmission networks under the service standard adjustment mechanism (SSAM) in the AA3 period ($ millions at 30 June 2017; penalties are shown in red, capped values are underlined)

Performance measure	2012/13	2013/14	2014/15	2015/16	2016/17
Distribution reliability performance measures					
System average interruption duration index (minutes)					
CBD	0.95	0.15	-0.44	-0.17	0.49
Urban	19.80	17.06	19.63	26.46	18.81
Rural short	6.50	9.02	6.21	9.71	7.93
Rural long	-7.42	-6.59	-6.85	-0.03	-3.16
System average interruption frequency index (interruptions)					
CBD	1.06	-0.58	-0.29	0.38	0.29
Urban	12.11	13.92	16.34	27.24	20.58
Rural short	2.45	10.79	7.11	12.76	12.51
Rural long	-5.05	-5.05	-3.93	0.79	1.23
Call centre performance (%)	1.37	2.38	2.79	1.74	1.92
Total distribution SSAM (uncapped)	**31.78**	**41.11**	**40.58**	**78.87**	**60.60**
% of distribution target revenue	*4.2%*	*5.4%*	*4.5%*	*7.7%*	*5.4%*
Total distribution SSAM (capped)	**31.78**	**37.75**	**40.58**	**51.43**	**56.12**
Transmission reliability performance measures					
Circuit availability (%)	2.43	-0.27	3.87	5.05	7.21
System minutes interrupted					
Radial networks	0.08	-0.34	0.03	0.16	0.14
Loss of supply event frequency (interruptions)					
>0.1 and ≤1.0 system mins.	0.52	0.28	0.00	0.36	0.32
>1.0 system minutes	0.18	0.18	0.36	0.18	0.00
Average outage duration (mins.)	-0.46	-0.27	-0.06	-0.52	0.17
Total transmission SSAM (uncapped)	**2.75**	**-0.42**	**4.21**	**5.23**	**7.84**
% of transmission target revenue	*0.6%*	*-0.1%*	*1.2%*	*1.6%*	*2.7%*
Total transmission SSAM (capped)	**2.75**	**-0.42**	**3.54**	**3.20**	**2.90**

Proposed revisions

1808. Western Power proposed the following revisions to the service standard adjustment mechanism for the fourth access arrangement period:

- Not apply service standard targets during the 2017/18 financial year.
- Set service standard targets at the average of the 50th percentile of probability distributions fitted to historical performance data for the remainder of the fourth access arrangement period.
- Adjust the SAIDI and SAIFI Rural long service standard targets for the improvement in service expected to result from the Kalbarri microgrid project.
- Use the value of customer reliability estimates from the Australian Energy Market Operator's (AEMO) study completed in 2014 to set distribution reliability incentive rates.
- Use updated revenue-at-risk values, and revised weightings to account for the proposed removal of the system minutes interrupted (radial networks) performance measure.

Submissions on Western Power's proposal

1809. Submissions referencing Western Power's proposed revisions to the service standard adjustment mechanism were received from Perth Energy, Synergy and the Western Australian Council of Social Service (WACOSS).

1810. Perth Energy questioned the magnitude of the increase in revenue-at-risk against Western Power's claim that the proposed service standard targets will be the same or more stringent than those applied during the third access arrangement period.[369]

1811. Synergy stated the service standard targets applied during the third access arrangement period should be maintained into the fourth access arrangement period and questioned the transparency of the method applied by Western Power to determine incentive rates on the transmission network.[370]

1812. WACOSS questioned whether an appropriate balance had been struck between service quality and price, noting the outcome of the mechanism in the third access arrangement period will affect household electricity bills:

> We note for example that the settings for the incentive mechanisms under AA3 to provide financial rewards where WP has exceeded its benchmarks means in practice they will be recovering half a billion dollars in profits from customers over AA4 ($270m on cap ex and $230m on op ex), which will mean in practice an additional $5 per year to the average household bill.[371]

1813. WACOSS also recommended careful examination of customer willingness to pay (values of customer reliability) in setting service standard benchmarks and targets.

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[369] Perth Energy, Submission to the Economic Regulation Authority regarding Western Power's Proposed Revisions to the Access Arrangement for the Western Power Network (2018-2022), November 2017.

[370] Synergy, *AA4 Submission No. 5: Western Power's proposed price control mechanisms*, 11 December 2017, pp. 77-8.

[371] Western Australian Council of Social Service, *Submission to the Proposed Access Arrangement for the AA4 period*, 11 December 2017.

Considerations of the ERA

1814. The following amendments were considered in the draft decision and are addressed below:

- Application of the service standard adjustment mechanism during 2017/18 financial year.
- Application of the service standard adjustment mechanism for the remainder of the fourth access arrangement period.
- Setting service standard targets at the average of the 50th percentile of the probability distributions of best fit to historical performance data.
- Adjusting rural long service standard targets to account for the improvement in service expected from the Kalbarri microgrid project.
- Using value of customer reliability estimates derived from AEMO's 2014 study to set distribution reliability incentive rates.
- Using updated revenue-at-risk estimates and revised weightings to set the transmission and call centre incentive rates.

Application of the service standard adjustment mechanism during the 2017/18 financial year

1815. Due to the delay in the commencement of AA4, Western Power proposed that service standard targets not be set for the 2017/18 financial year, which would result in Western Power not earning any rewards or incurring any penalties under the service standard adjustment mechanism in that year.[372]

1816. The ERA considered the continuation of existing incentive rates would not be consistent with the Code objective and approved the element of the proposal that removed rewards and penalties for the 2017/18 financial year.

1817. Consistent with Western Power's intention to maintain service performance into the fourth access arrangement period, and a submission from Synergy which sought to maintain performance reporting against service standard benchmark and targets, the ERA considered the application of existing service standard targets to be consistent with the Code objective and required the following amendment to Western Power's proposal:

> **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 revised proposal

1818. Western Power did not accept the required amendment and sought to apply incentive rates, but not service standard targets, for the 2017/18 financial year.

1819. Western Power stated in its revised proposal that, although the required amendment in the draft decision would achieve the same neutral outcome for customers as that

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[372] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 98, para. 356.

proposed by Western Power, the incentive rates under the service standard adjustment mechanism are necessary for internal investment governance:

> 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…
>
> 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.[373]

1820. Western Power also stated that its proposal to not apply service standard targets in the 2017/18 financial year was consistent with the Access Code and "therefore can and must be accepted by the ERA."[374]

Further submissions

1821. No further submissions were received referencing the required amendment to maintain service standard targets for the 2017/18 financial year at the levels applied during the third access arrangement period.

Considerations of the ERA

1822. The ERA considered the following matters to determining the compliance of Western Power's proposal to apply incentive rates, but not service standard targets, in the 2017/18 financial year:

- application of service standard targets in 2017/18
- application of incentive rates in 2017/18.

Application of service standard targets in 2017/18

1823. In the draft decision requiring the application of service standard targets (but not incentive rates) in 2017/18, the ERA considered:

- Western Power's intention to maintain service performance at the level achieved during the third access arrangement period, including continued application of service standard benchmarks from the third access arrangement period.
- Synergy's submission, which sought to maintain the application of the service standard adjustment mechanism, or performance reporting, for the 2017/18 financial year.
- The requirement for the ERA to have regard to the service standard adjustment mechanism before imposing a civil penalty for non-compliance with service standard benchmarks under section 11.6 of the Access Code.

[373] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 196.

[374] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 196, para. 1144.

- The requirement for the ERA to report annually on Western Power's performance against service standard benchmarks (section 11.2).

1824. Western Power stated in its revised proposal that service standard targets are not required for the purpose of determining penalties for non-compliance with minimum service standard benchmarks under section 11.6 of the Access Code:

> 1141. We do not agree with the Economic Regulation Authority'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.[375] [emphasis in original]

1825. Having regard to Western Power's revised proposal, the ERA considers:

- Service standard targets are not necessary for determining penalties for non-compliance with service standards benchmarks under section 11.6 of the Access Code.
- The continued application of service standard targets at the levels applied in the third access arrangement period would not be consistent with the Code objective.
- The retrospective application of service standard targets would not be consistent with the Code objective.

1826. Western Power is not required to report performance in the 2017/18 financial year against service standard targets that had applied in the third access arrangement period.

Application of incentive rates in 2017/18

1827. Western Power stated in its revised proposal that incentive rates that reflect customers' willingness to pay for service reliability are essential to its internal 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.
>
> …
>
> 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

[375] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p.196, para. 1141.

> 1137. The incentive rates are an important component of Western Power's investment governance, therefore it is vital the ERA approves the values for AA4, even if they are not going to have an effect in the first year of the period.[376]

1828. Under the Access Code, Western Power's internal investment governance process is not a prescribed matter for consideration by the ERA.

1829. Western Power stated in response to a further enquiry that "there is no need for an explicit Code provision that requires or authorises the Regulator to approve incentive rates for a given year, independent of the service standard adjustment mechanism."[377] Western Power referred to the general requirement for the ERA to determine whether a proposed access arrangement meets the Code objective under section 4.28:

> Western Power submits the ERA is required by the Code to approve incentive rates in this case as they are relevant to Western Power's internal investment governance process, which helps promote efficient investment in the network.[378]

1830. Western Power also referred to the broad discretion available to the ERA, under section 4.29 of the Code, to approve a proposed access arrangement that contains something not listed in section 5.1.[379]

1831. The ERA considers that it is not required to:

- approve incentive rates in 2017/18, independently of the service standards adjustment mechanism under the Access Code; or

- exercise its discretion under section 4.29(b) of the Access Code to approve a proposed access arrangement containing something not listed in section 5.1 of the Access Code.

1832. Further, Western Power is bound by the Access Code to act prudently, efficiently, and in accordance with good electricity industry practice with reference to the service standard benchmark levels of performance.

1833. Section 1.3 of the Access Code defines a service provider "efficiently minimising costs" as one seeking to achieve the lowest sustainable cost of delivering services not below the service standard benchmark level of performance:

> … 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.

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[376] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, pp. 194-5, paras. 1134, 1136-7.

[377] Western Power, Response to ERA061 – follow up query on 24 August 2018- Service standard incentive rates, 28 August 2018.

[378] Western Power, Response to ERA061 – follow up query on 24 August 2018- Service standard incentive rates, 28 August 2018.

[379] Western Power, Response to ERA061 – follow up query on 24 August 2018- Service standard incentive rates, 28 August 2018.

1834. In its initial access arrangement information, Western Power stated that it would continue to meet the service standard benchmark level of performance that had applied in the third access arrangement period as no investment in service improvement had been included in the expenditure forecast for AA4:

> These SSBs will be set at the same level for each year because no investment in service improvement has been included in the AA4 expenditure forecast.
>
> We do not expect the ERA to make a final decision on the revised proposed access arrangement until June 2018 at the earliest.
>
> As a result, for 2017/18 and until the AA4 period commences we will continue to operate and invest in the business to meet the current AA3 suite of SSBs.[380]

1835. The application of incentive rates for the purpose of the service standard adjustment mechanism during the remainder of AA4 is considered below.

Application of the service standard adjustment mechanism for the remainder of the fourth access arrangement period

1836. The ERA also considered the removal of financial rewards and penalties under the service standard adjustment mechanism for the remainder of the AA4 period, given:

- Western Power's stated intention to maintain service performance in AA4 at levels attained during AA3
- The substantial reward achieved by Western Power during AA3, including having reached the reward cap in multiple and consecutive years on both of the distribution and transmission networks.
- Public submissions that questioned whether the service standard adjustment mechanism was operating efficiently to deliver service performance improvements that were valued by customers.
- The uncertain outcome of the service standard adjustment mechanism in AA4, including analysis which indicated that Western Power would derive a material reward by maintaining service performance at levels equivalent to those achieved during the third access arrangement period.
- The continued requirement for Western Power to report actual performance against service standard benchmarks and targets.
- The incentive structure of the gain share mechanism.

1837. The ERA required the removal of financial rewards and penalties in the service standard adjustment mechanism in the draft decision on the proposed access arrangement for AA4:

> **Required Amendment 36**
>
> Western Power must remove the financial penalties and rewards from the service standard adjustment mechanism.

[380] Western Power, Access Arrangement Information, Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 89, paras. 306-8.

Western Power's revised proposal

1838. Western Power did not accept the required amendment to remove financial rewards and penalties from the service standard adjustment mechanism AA4.[381]

1839. Western Power stated the amendment changes the fundamental operation of the mechanism, because the removal of financial rewards and penalties would:

- Not be consistent with the specific Access Code requirements or the Code objective.
- Not be consistent with the purpose of the mechanism to offset incentives to outperform forecast operating expenditure at the expense of service performance.
- Allow service performance to deteriorate without penalty despite customers having already paid for service improvements achieved in AA3.
- Remove the incentive for Western Power to undertake further investment to improve service performance where it is valued by customers.
- Undermine Western Power's investment governance and operational decision making process.[382]

Further submissions

1840. Energy Networks Australia stated the draft decision to remove financial rewards and penalties from the service standard adjustment mechanism compromises the operation of incentive-based regulation:

> Energy Networks Australia support the use of incentive-based mechanisms to promote continuous, effective and stable financial incentives for efficient expenditure and service quality. The ERA's draft decision compromises the operation of incentive-based regulation by removing the financial penalties and rewards from the service standard adjustment mechanism.[383]

1841. Energy Networks Australia also referred to the long term interests of consumers, stating the rewards earned by Western Power in AA3 indicate the regulatory framework is working effectively:

> It is understood that Western Power customers overall are not looking for improvements in reliability, if it is likely to increase network charges. An incentive-based scheme has the advantage of promoting innovation and discovery of new technological opportunities that enable a business to improve its level of service at a lower cost than the value to customers of that improved service performance. Furthermore, the service standard adjustment mechanism has a longer-term role in balancing incentives for cost reduction with incentives to maintain or improve service quality, which is in the long term interests of consumers.
>
> We note that the rewards earned by Western Power under the current service standard adjustment mechanism and proposed to be recovered are likely to indicate that the

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381 Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 97.

382 Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 97, para. 1156.

383 Energy Networks Australia, Submission on the draft decision, 14 June 2018, p. 2.

regulatory framework is working effectively because the regulated business is responding to efficiency and service quality incentives.[384]

Considerations of the ERA

1842. In the draft decision, the ERA considered the risk of a material increase in costs to customers to be sufficient to void the scheme by removing rewards and penalties for AA4. The financially neutral outcome of a mechanism comprising nil rewards and penalties would be identical to that predicted by Western Power if it were to maintain service performance in the AA4 period under a scheme with non-zero rewards and penalties.

1843. Western Power submitted that the draft decision was not consistent with the Access Code, which requires an access arrangement to contain a service standard adjustment mechanism, including a financial component.[385]

1844. Western Power also rejected the precedent established in the first access arrangement period (AA1), in which it was determined that the service standard adjustment mechanism did not require a financial incentive, as "mistaken".[386]

1845. Western Power acknowledged that, in isolation, sections 6.29 and 6.30 of the Code do not expressly require the service standard adjustment mechanism to include a financial component although, to give operation to section 6.4(a)(vi) of the Access Code, the "amount" of target revenue (if any) must be a financial quantity.

1846. Western Power stated that the draft decision to remove financial rewards and penalties effectively nullified the service standard adjustment mechanism, contrary to section 6.30 of the Access Code, which requires the access arrangement to contain a service standard adjustment mechanism.

1847. Western Power also cited the opinion expressed in the expert report, prepared by ACIL Allen, that the removal of financial rewards and penalties under the service standard adjustment mechanism was not consistent with the Code objective since it would remove the incentive to improve service performance where it may be economically efficient to do so.[387]

1848. Western Power also noted that, although the Access Code requires an access arrangement to contain an investment adjustment mechanism (section 6.15), section 6.16(b) states that no adjustment may be applied to target revenue in the next access arrangement in respect of any investment difference. In contrast, the Access Code does not state that the service standard adjustment mechanism may not be applied in any year.

1849. The ERA acknowledges that the operation of the service standard adjustment mechanism, as an adjustment to target revenue under the price control objectives of section 6.4 of the Access Code, implies a financial component.

[384] Energy Networks Australia, Submission on the draft decision, 14 June 2018, p. 2.

[385] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 98.

[386] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 98, para. 1159.

[387] Western Power, Revised proposed access arrangement information, Attachment 14.1, ACIL Allen Consulting Report on the Service Standard Adjustment Mechanism, 14 June 2018, p. 25.

1850. The Access Code does not prescribe a requirement, however, that incentive rates under the service standard adjustment mechanism must be non-zero. The primary consideration of the ERA is whether the application of nil incentive rates to the service standard adjustment mechanism is consistent with the Code objective, required under section 6.31(b).

1851. Since the Access Code does not prescribe the parameters or structure of the service standard adjustment mechanism, the similarity of objectives with the service target performance incentive schemes administered by the Australian Energy Regulator is instructive.

1852. Section 2.3(a)(1) of the service target performance incentive scheme for transmission network service providers, for example, permits the Australian Energy Regulator to "add, remove or vary a parameter" of the scheme, suggesting any of these options may be consistent with the objectives of the scheme under particular circumstances.[388] Performance parameters may also be assigned a nil weighting under the scheme.

1853. On the other hand, section 2.7(a) of the service target performance incentive scheme for distribution network service providers permits the Australian Energy Regulator to suspend the operation of the scheme at any time:

> At any time during a regulatory control period in which a scheme applies to a [distribution network service provider], the [Australian Energy Regulator] may decide whether the scheme or a component of the scheme should be suspended for a regulatory control period or a portion of a regulatory control period.[389]

1854. The Australian Energy Regulator explained that suspension of the scheme may be considered if the financial cap (revenue-at-risk) was reached in any year and the risk to customers of maintaining the scheme exceeded the risk of deteriorating service performance:

> The role of the scheme is to provide incentives for [distribution network service providers] to maintain and improve service performance, as set out in clause 6.6.2 (a) of the [National Electricity Rules]. The proposed scheme is therefore designed to encourage sustainable improvements to service rather than focusing on one-off infrequent events. Consistent with this, the purpose of specifying exclusions is to limit the risk that single very large events may result in unreasonable penalties being applied, the financial cap being reached and the scheme being suspended.[390]

1855. The Australian Energy Regulator also explained that the suspension of the service target performance incentive scheme should be considered only in extreme circumstances, should not be relied on as a risk mitigation strategy, and should avoid creating an asymmetric risk profile such that suspension of the scheme would protect a service provider from the downside risk of service under-performance:

> However the [Australian Energy Regulator] considers that relying on the possibility of suspending the scheme results in an asymmetric risk profile whereby the [distribution network service provider] has a large upside benefit but, in the event that the scheme

[388] Australian Energy Regulator, FINAL Electricity transmission network service provider Service target performance incentive scheme, Version 5 (corrected), October 2015.

[389] Australian Energy Regulator, Draft Electricity distribution network service providers Service target performance incentive scheme, Version 2, December 2017.

[390] Australian Energy Regulator, Explanatory statement and discussion paper, Proposed Electricity distribution network service providers service target performance incentive scheme, April 2008, p. 24.

> is suspended, it is not exposed to the full downside risk of an uncapped scheme. The [Australian Energy Regulator] considers that suspending the scheme should only be considered in extreme circumstances and should not be relied upon as a risk mitigation strategy.[391]

1856. Consequently, the application of nil incentive rates under the service standard adjustment mechanism may be consistent the Code objective if the uncertain outcome of the mechanism cannot be mitigated, and is considered to be inconsistent with the objective of promoting efficient investment in networks and market competition in Western Australia. That is, if the risk to customers of increasing costs of service performance that are not aligned with customers' valuations of service reliability exceeds the risk of deteriorating service performance without the mechanism.

1857. In considering whether the level of uncertainty is sufficient to require the effective suspension of the scheme in the AA4 period, reference is again made to the purpose and operation of the service target performance incentive schemes administered by the Australian Energy Regulator. The purpose of the scheme for distribution network service providers is to offset the service provider's incentive to outperform forecast operating expenditure by under-providing service quality. This purpose is achieved by linking target revenue in the next regulatory period with estimates of customer valuations of service performance in the current period.[392]

1858. Western Power has acknowledged a similar objective for the service standard adjustment mechanism:

> 1122. The purpose of the [service standard adjustment mechanism] 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 [service standard targets].[393]

1859. Western Power also referred to the importance of the mechanism to ensure that customers continue to receive the level of service performance that has been funded by the adjustment to target revenue in the fourth access arrangement period.[394]

1860. ACIL Allen Consulting similarly advised that the service incentive scheme ensures that service performance is maintained or improved:

> A Service Standard Adjustment Mechanism (SSAM)… ensures that the incentive to out-perform is balanced by an incentive to not allow service levels to deteriorate.[395]
>
> …
>
> If a network service provider operates under an incentive-based economic regulatory framework with an efficiency carryover mechanism and no service incentive scheme, the incentive to out-perform opex forecasts is not balanced by an incentive to maintain

[391] Australian Energy Regulator, Draft decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015, June 2010, p. 639.

[392] Australian Energy Regulator, Electricity distribution network service providers Service target performance incentive scheme, Issues Paper, November 2007, p. 7.

[393] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 4.

[394] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 10, para. 65-6.

[395] Western Power, Revised proposed access arrangement information, Attachment 14.1, ACIL Allen Consulting Report on the Service Standard Adjustment Mechanism, 14 June 2018, p. 4.

> service levels. The network service provider has no incentive to economically efficiently invest to maintain or improve service performance.[396]

1861. Energy Networks Australia also supported the implementation of financial rewards and penalties in the service standard adjustment mechanism and referred to the promotion of technological innovation and long term interests of customers of maintaining or improving service quality:

> An incentive-based scheme has the advantage of promoting innovation and discovery of new technological opportunities that enable a business to improve its level of service at a lower cost than the value to customers of that improved service performance. Furthermore, the service standard adjustment mechanism has a longer-term role in balancing incentives for cost reduction with incentives to maintain or improve service quality, which is in the long term interests of consumers.[397]

1862. In conclusion, the ERA considers the Access Code objective may be satisfied with the application of non-zero incentive rates for the remainder of the AA4 period with additional risk mitigation measures to ensure that customers are not exposed to an unreasonable risk of increasing costs for service performance improvements that are not valued to the extent of the reward received by Western Power.

1863. In summary:

- The application of nil incentive rates in the service standard adjustment mechanism is not precluded by the Access Code, or inconsistent with the Code objective if the risk to customers of increased costs that do not correspond to the value they place on service reliability exceeds the risk of deteriorating service performance.
- The effective suspension of the service standard adjustment mechanism by the application of nil incentive rates should be considered only in extreme circumstances.
- An instance of the cumulative financial rewards or penalties exceeding the revenue-at-risk caps on the distribution or transmission networks in any year may qualify as an extreme circumstance, more so if the cap is exceeded concurrently on both networks, or in consecutive years on either network.
- Suspension of the mechanism should avoid creating an asymmetric risk profile such that the service provider avoids the risk of incurring penalties for deteriorating service performance.
- Other risk mitigation measures should be considered before the service standard adjustment mechanism is effectively suspended by the application of nil incentive rates.

1864. The ERA considers the application of non-zero rewards and penalties in the service standard adjustment mechanism for the remainder of the fourth access arrangement period, with additional or modified risk-mitigation measures, to be consistent with the Code objective.

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[396] Western Power, Revised proposed access arrangement information, Attachment 14.1, ACIL Allen Consulting Report on the Service Standard Adjustment Mechanism, 14 June 2018, p. 5.

[397] Energy Networks Australia, submission on the draft decision, 14 June 2018.

1865. Additional risk mitigation measures are discussed in subsequent sections.

Set the service standard target at the average of the 50th percentile of the distributions of best fit, selected subject to nominated threshold criteria

1866. Western Power proposed to set the service standard targets at the average value of the 50th percentile of multiple probability distributions fitted to historical performance data, selected subject to nominated threshold criteria.[398]

1867. The proposed method is a modification of that applied in the third access arrangement period in which service standard targets were set at the 50th percentile of the single probability distribution of best fit.

1868. For similar reasons as those considered in the assessment of the proposed method for setting service standard benchmarks, the method was considered to be inconsistent with the Access Code and was not approved in the draft decision for the following reasons:

- The service standard targets proposed by Western Power were not significantly different from those derived at the 50th percentile of the single distribution of best fit, undermining Western Power's claim that the proposed method resulted in more accurate target values.

- The process for determining the nominated selection threshold appeared to be arbitrary and based on the analysis of a single performance measure.

- The set of candidate distributions and those selected within the nominated threshold were also likely to vary over time.

- The improved statistical robustness of the proposed method was not objectively demonstrated.

1869. The draft decision required Western Power to set service standard targets at the 50th percentile of the single probability distribution of best fit:

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 revised proposal

1870. Western Power did not accept the required amendment and maintained its original proposal to set service standard targets at the average of the 50th percentile of the probability distributions selected according to nominated threshold criteria.[399]

1871. Western Power cited similar reasons as those used to support its proposed method to set service standard benchmarks:

[398] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 98, para. 354.

[399] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 207.

- The multi-model averaging process is consistent with the state of-the-art practice in statistical inference.
- The proposed approach reduces volatility and variability of the service standard targets.
- 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.

1872. Western Power also proposed a step-change adjustment to the service standard target for the loss of supply event frequency performance measure for events greater than 1.0 minute (LOSEF >1.0), to reflect a new system protection modification that increased the load shed due to interruptions in the Eastern Goldfields.[400]

Further submissions

1873. Western Australian Major Energy Users (WAMEU) expressed concern that electricity was an increasingly unaffordable but essential service, and the cost of Western Power's services was a significant contributor to the unaffordability problem. The service standard targets set for AA4 were considered to be too lenient and non-neutral:

> WAMEU sees that in general, [Western Power] is enjoying significant bonuses from exceeding service standard targets and yet the new targets do not require Western Power to have to work hard to enjoy a bonus.[401]

1874. WAMEU also proposed that benchmarks (interpreted to include service standard targets) should be adjusted on an ongoing, rolling five-year basis such that improved performance was sustained and rewards were restricted to incremental improvements:

> As the benchmarks are incentivised to show a continuing improvement in performance, the rolling 5-year performance approach provides continuing pressure to improve performance and limits the ability of [Western Power] to get easy bonuses.[402]

Considerations of ERA

1875. The ERA considered the following matters to determine the compliance of the proposed method for setting service standard targets with the requirements of the Access Code:

- the proposed method for deriving service standard targets
- annually updated service standard targets.
- proposed step-change adjustments.

[400] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 208, para. 1226.

[401] Western Australia Major Energy Users, submission to draft decision on Wester Power's fourth access arrangement, June 2018, p. 55.

[402] Western Australia Major Energy Users, submission to draft decision on Wester Power's fourth access arrangement, June 2018, p. 55.

Method for setting service standard targets

1876. The purpose of the service standard adjustment mechanism parallels that of the service target performance incentive schemes administered by the Australian Energy Regulator, which is to offset the service provider's incentive to achieve operating expenditure efficiencies at the cost of service quality, by linking target revenue in the next regulatory period with service performance outcomes in the current period.[403]

1877. The Australian Energy Regulator initially considered several methods for setting performance targets under the service target performance incentive scheme for distribution network service providers:

- The level of performance in the most recent year, if there is minimal volatility in past performance.
- Average historical performance, when performance is reasonably consistent and a good record of performance data is available.
- Extrapolated trend of past performance, when the reasons for the trend are understood.
- Moving average of past performance when there is some volatility and an underlying trend.
- Externally defined benchmarks, modified for individual operating factors.[404]

1878. In its final decision on the application of the scheme to distribution network service providers, the Australian Energy Regulator determined that performance targets were to be based on average performance over the past five years, including an adjustment for planned reliability improvements.[405]

1879. The method of averaging historical performance on which rewards and penalties have been paid or levied also ensured that subsequent targets were linked directly to financial outcomes of the incentive scheme. A single adverse event, for example, would result in an immediate penalty under the service incentive scheme and would then be reflected in a revised performance target in the subsequent period:

> Distributors will only receive a financial reward after actual improvements are delivered to the customers. More importantly, a distributor can only retain its rewards if it can *maintain the reliability improvements* on an ongoing basis. Once an improvement is made, the benchmark performance targets will be tightened in future years. That is, the distributors' reliability targets for future years will be based on the level of performance that they have achieved to date. The reward for their improved performance is paid to the distributor (by customers) for five years. After which, customers will retain the benefit of the reliability improvement.

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[403] Australian Energy Regulator, Electricity distribution network service providers Service target performance incentive scheme, Issues Paper, November 2007, p. 7.

[404] Australian Energy Regulator, Electricity distribution network service providers Service target performance incentive scheme, Issues Paper, November 2007, p. 7.

[405] Australian Energy Regulator, Electricity distribution network service providers Service target performance incentive scheme, Final Decision, June 2008, p. 10.

> If the reliability levels should fall in the future, the distributor will receive penalties for not meeting the tightened targets—hence, the reward paid to the distributor will be returned to customers if the reliability levels fall.[406] [emphasis in original]

1880. The Australian Energy Regulator also noted that setting performance targets based on actual historical performance had the advantages of simplicity and transparency, with the underlying assumption being that service providers would have sufficient scope to improve performance with appropriate incentives.[407]

1881. The service component of the service target performance incentive scheme for transmission network service providers also requires performance targets to be set based on average performance over the most recent five-year period, although service providers are permitted to propose alternative methods and time periods. The Australian Energy Regulator may reject proposed values if they are determined to be inconsistent with the objectives of the scheme.[408]

1882. In AA3, Western Power proposed service standard targets to align with an "expected" level of service performance, comparable with that level of performance experienced by customers in the preceding five-year period. Service standard benchmarks, as defined in the Access Code, were established as minimum performance standards:

> A further revision to the service standard framework is that there will be a strong financial incentive to deliver an **expected level** of service. This *expected level* of service is higher than the minimum standard and is comparable with the level that customers have experienced over the last five years. The financial incentive to achieve this *expected level* of performance will be provided via the service standards adjustment mechanism (SSAM).[409] [emphasis in original]

1883. In its proposal to set the service standard targets at the 50th percentile of a probability distribution fitted to historical performance data, Western Power conflated the expected level of performance with that which would be achieved "50 per cent of the time", or at the 50th percentile of historical performance data:

> Under the SSAM the *expected level* of performance against the service standard benchmark [target] will be set at a level that we would *expect* to achieve 50% of the time.[410] [emphasis in original]
>
> …
>
> The expected performance is determined by the 50th percentile of the historical data for the last 5 years. All else being equal, actual performance is expected to be greater than the expected performance level 50% of the time and below this level 50% of the time.[411]

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[406] Australian Energy Regulator, Issues paper, Reviewing the Service Target Performance Incentive Scheme and Establishing a new Distribution Reliability Measures Guidelines, Electricity distribution network service providers, January 2017, p. 8.

[407] Australian Energy Regulator, Service target performance incentive scheme (incorporating incentives based on the market impact of transmission congestion) Explanatory Statement, Draft, November 2007, p. 28.

[408] Australian Energy Regulator, FINAL Electricity transmission network service providers Service target performance incentive scheme, Version 5 (corrected), October 2015.

[409] Western Power, *Access arrangement information for 1 July 2012 to 30 June 2017*, September 2011, p. 91.

[410] Western Power, *Access arrangement information for 1 July 2012 to 30 June 2017*, September 2011, p. 91.

[411] Western Power, *Access arrangement information for 1 July 2012 to 30 June 2017*, September 2011, p. 91, footnote 73.

> …
>
> As discussed in section 5.5.2, the *expected level* of performance will be the performance we will expect to achieve 50% of the time when compared to the average actual performance over the last five years if we undertake the actions and investment planned.[412] [emphasis in original]

1884. The intention of the mechanism was that the scheme would deliver a neutral outcome if performance was maintained at the expected level of performance:

> The financial reward (and penalty) has been set to reflect the likely value to customers of achieving the expected level of performance compared to the minimum level of performance. Where we achieve the *expected level* of performance, the value of the scheme is expected to be zero.[413] [emphasis in original]
>
> …
>
> Therefore, for AA3 the SSAM details a financial penalty if we deliver service that is better than the service standard benchmark but worse than the *expected level* of performance (which we expect to provide at least 50% of the time). A reward is only provided where performance against the service standard benchmark [target] is better than the expected level of performance.[414] [emphasis in original]

1885. In fact, the expected (or average) level of performance will coincide with that which would be achieved 50 per cent of the time (at the 50th percentile) to achieve a neutral outcome under the service standard adjustment mechanism in only two precise and improbable circumstances:

- If actual performance is symmetrically distributed throughout the five-year performance period (including a hypothetical nil volatility scenario).

  or

- If financial rewards and penalties are non-linear and perfectly aligned with an actual, skewed performance distribution.

1886. Western Power's proposed method of setting service standard targets at the 50th percentile of historical performance data was approved by the ERA for AA3 due to:

- A perception that the proposed method would establish a performance target at the level that would be realised on average:

> Instead, Western Power has proposed SSAM mechanism service standard targets which correspond to the expected value of performance – that is, the performance expected to be realised on average.[415]

- An interpretation of the proposed method being consistent with that applied by the Australian Energy Regulator in the service target performance incentive scheme for transmission network service providers:

[412] Western Power, *Access arrangement information for 1 July 2012 to 30 June 2017*, September 2011, p. 96.

[413] Western Power, *Access arrangement information for 1 July 2012 to 30 June 2017*, September 2011, p. 94.

[414] Western Power, *Access arrangement information for 1 July 2012 to 30 June 2017*, September 2011, p. 95.

[415] Economic Regulation Authority, Draft decision on proposed revisions to the access arrangement for the Western Power network, 29 March 2012, p. 249, para.1058.

> 1099. The Authority notes that the equivalent [performance targets] set by the Australian Energy Regulator for its Service Target Performance Incentive Scheme are derived from the 50 per cent PoE average performance levels based on the most recent five years of data, while the lower bound 'collars' are set at 1.96 standard deviations away from the average performance (consistent with a 95 per cent confidence interval).[416]

- Technical analysis which demonstrated the similarity of results achieved by the proposed method with a simple average of annual performance data:

> The statistical algorithm used by Western Power to calculate its proposed AA3 SSAM targets was complex. We considered that if this algorithm was valid it would give a result similar to a simple average of the numbers shown in Tables 4.10 and 4.11. This was indeed the case and we accept the validity of the statistical approach used by Western Power to calculate its targets. However, our preference is to avoid complex statistical analysis and use an approach that is more transparent and can be readily understood by users. Given the small difference between the statistical analysis results and the results found using a simple average, we see little value in the more complex analysis. We have therefore proposed benchmark/SSAM target levels that have been calculated using a simple average.[417]

1887. In its proposal to set service standard targets for AA4, Western Power referred to maintaining the average level of service performance:

> 304. Over the course of the AA3 period, Western Power achieved improvements in the majority of its service performance measures. To ensure that we maintain the average level of service our reference service customers have received over recent years, Western Power proposes to change its methodology for setting SSBs (except street lights) as follows…[418]

1888. Western Power also referred to the average or expected level of performance as that which would be achieved 50 per cent of the time:

> 196. The AA3 SSAM was designed so that, on average, performance would exceed the SST 50 per cent of the time, and fall below the SST 50 per cent of the time, the net outcome being that overall service levels are maintained.[419]
>
> …
>
> Western Power's proposed SSAM provides financial rewards and penalties for service that is better or worse than the expected level of performance (which we expect to achieve 50 per cent of the time).[420]

1889. Western Power also suggested that service performance would be maintained at levels achieved in the final year(s) of AA3:

> 238. Therefore, the service incentive framework proposed for the AA4 period is designed to consolidate the improvements made over the past five years, and maintain overall performance at the levels achieved at the end of the AA3 period… [O]ur

[416] Economic Regulation Authority, Draft decision on proposed revisions to the access arrangement for the Western Power network, 29 March 2012, p. 249, para.1099.

[417] Geoff Brown and Associates, Technical Review of Western Power's proposed access arrangement for 2012-2017, Final (Public Version), 27 March 2012, p. 34.

[418] Western Power, Access arrangement information, Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 89, para.304.

[419] Western Power, Access arrangement information, Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 58, para.196.

[420] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 97, para.349.

> proposal is that the service incentive framework be designed to provide an incentive for Western Power to keep overall performance at current levels.[421]

1890. Western Power proposed, however, to derive service standard targets within the service standard adjustment mechanism by averaging the 50th percentile values sampled from multiple distributions of best fit, consistent with its proposed method for setting service standard benchmarks:

> 353. Western Power proposes to set its SSTs that apply to the SSAM using a similar method as used for the AA3 period, in that the SSTs are set at the 50th percentile. As discussed in section 6.6.3, we propose to use the average of the 50th percentile of the distributions of best fit, consistent with the setting of the SSBs.[422]

1891. The draft decision referred to analysis completed by GHD Advisory, which demonstrated that the proposed service standard targets would deliver a material net reward to Western Power if performance during the AA4 period was maintained at equivalent (average) levels as those achieved during AA3.[423] This result derives from two underlying sources of bias:

- Setting the service standard targets at the 50th percentile values in skewed performance distributions.

  and

- Using a data set comprised of 12-monthly rolling-sum values, which overweights earlier, lower standard performance in an improving performance scenario.

1892. Both of these biases are evident in Table 176, below. The first bias is demonstrated in the difference between the average (or expected) level of performance (column B) with the level of performance achieved at the 50th percentile estimated by various methods (columns C, D, or E), using the 60 monthly rolling-sum data points. Skewness may be positive or negative.

1893. The second bias is evident in the differences between the average value of five annual data points (column A) and the average value of 60 data points generated as 12-month rolling sum values (column B). Under a neutral performance trend across the sample period, these values would be identical. However, in all cases, the average of 60 rolling-sum data points would result in less ambitious service standard targets than those derived from the average value of five annual performance outcomes. This result is consistent with an improving performance trend and the over-weighting of earlier performance in the monthly rolling-sum data set.

[421] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 73, para. 238.

[422] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 73, para. 238.

[423] GHD Advisory, Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22, Draft report, March 2018, p. 245.

Table 176 Comparison of performance measures for AA3 derived at the average of five annual data points, 60 monthly rolling sum data points, the 50th percentile of the single distribution of best fit, and the average of the 50th percentiles of probability distributions selected according to nominated threshold criteria

Performance measure	(A) Average of 5 annual performance values	(B) Average of 60 monthly rolling sum values	(C) 50th percentile of 60 monthly rolling sum values	(D) 50th percentile of single distribution of best fit	(E) Average of 50th percentile of multiple distributions
Distribution reliability performance measures					
System average interruption duration index (minutes)					
CBD	17.7	18.2	17.7	17.9	17.8
Urban	106.8	109.4	106.8	108.3	108.7
Rural short	188.6	190.0	190.9	191.9	190.4
Rural long	693.1	694.8	690.1	681.6	681.3
System average interruption frequency index (interruptions)					
CBD	0.12	0.13	0.14	0.14	0.14
Urban	1.09	1.12	1.13	1.13	1.12
Rural short	1.96	2.00	2.01	2.00	2.01
Rural long	4.65	4.74	4.80	4.73	4.73
Call centre performance (%)	92.0	91.7	92.2	92.2	92.2
Transmission reliability performance measures					
Circuit availability (%)	98.5	98.5	98.5	98.5	98.5
Loss of supply event frequency (interruptions)					
>0.1 and ≤1.0 system mins.	16.6	17.4	17	17	17
>1.0 system minutes	1.0	0.8	1	1	1
Average outage duration (mins.)	860	887	871	866	871

Note: *Performance data has been adjusted for the proposed and approved major event day threshold method for the fourth access arrangement period to maintain consistency*

1894. A consequence of setting service standard targets at a value other than the simple average of five annual performance outcomes is that Western Power would derive a material net reward in the AA4 period by maintaining performance at an equivalent (average, or expected) level as that achieved during AA3. Alternatively, Western Power may achieve a neutral outcome under the service standard adjustment mechanism while allowing service performance to deteriorate from the average levels achieved in AA3.

1895. An alternative scenario of a declining performance trend would result in Western Power being penalised for maintaining an average level of performance.

1896. Consequently, the method proposed by Western Power for setting service standard targets is not consistent with the Code objective.

1897. The service standard adjustment mechanism will only achieve a neutral outcome while maintaining average levels of service performance if service standard targets reflect the level of performance the service provider expects to achieve, on average.

Annually updated service standard targets

1898. The ERA also considered Western Australia Major Energy Users' proposal to revise service standard targets annually. The proposal would ensure performance deviations from target levels are reflected immediately in subsequent service standard targets, and rewards or penalties would be paid or incurred on incremental service improvement or deterioration, rather than sustained deviations from a fixed, historical target value for the regulatory period.

1899. The proposal to implement rolling performance targets is consistent with the method applied by Western Power in the second access arrangement period (AA2). The method was revised in AA3 because Western Power did not include any investment in service performance improvements in expenditure forecasts for AA3. Western Power reasoned that, if performance targets were adjusted annually, increasing levels of expenditure would be required to avoid penalties, which would lead to increased network tariffs.[424]

1900. The Australian Energy Regulator also considered a similar proposal from the Major Energy Users Inc. in its draft decision on the review of the service target performance incentive scheme for transmission network service providers in 2015. The Australian Energy Regulator considered that transmission network service providers had not had sufficient time to enable lead indicators introduced in the previous revision to develop, but reserved its consideration to move to rolling performance targets in subsequent reviews.[425]

1901. Major Energy Users Inc. reiterated its concern that service providers were gaining unearned rewards by funding reliability improvements through approved maintenance or replacement expenditure.[426]

1902. In a further response to an enquiry from the ERA, Western Power stated that the ERA may not reject a proposed access arrangement on the grounds that another proposal might be better or more effectively satisfy the Code objective.[427]

1903. Western Power also stated the uncertainty of rolling benchmarks and targets will not result in an effective compliance or incentive regime because:

- The incentive framework is intended to deliver sustained performance improvements, which would not be delivered with moving targets and benchmarks.
- Western Power's objective is to maintain average levels of service performance achieved in the prior period and has forecast capital and operating expenditure consistent with this objective.

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[424] Western Power, *Access arrangement information for 1 July 2012 to 30 June 2017*, September 2011, p. 96.

[425] Australian Energy Regulator, Explanatory statement, Draft electricity transmission network service providers service target performance incentive scheme, June 2015, p. 11.

[426] Major Energy Users Inc., Submission to Australian Energy Regulator, TNSP Service Target Performance Incentive Scheme Review, 28 July 2015

[427] Western Power, Response to ERA enquiry, ERA072 Service standard targets, 5 September 2018.

- The lag between investment and observed reliability improvements and annually revised targets would present a challenge to long term investment objectives.

- The uncertainty of annually revised targets would necessitate a more conservative investment program and hence, increased forecast operating expenditure.

- Annually updated targets would impose an additional resource requirement on Western Power to audit and analyse performance data.

1904. Sections 4.12 and 4.17 of the Access Code require the ERA to consider any public submissions in determining whether a proposed access arrangement satisfies the Code objective and requirements of Chapter 5 (and Chapter 9, if applicable).

1905. The ERA considers the proposal to implement annually revised service standard targets and benchmarks may be consistent with the Access Code objective of promoting efficient investment or, alternatively, discouraging inefficient investment. Annually revised service standard benchmarks and targets may prevent the service provider from accumulating rewards within a regulatory period disproportionately to the level of investment in service performance.

1906. The ERA considers, hwoever, that insufficient evidence has been presented to demonstrate that the five-yearly review of service standard targets is inconsistent with the requirements of the Access Code, including the Access Code objective.

1907. The ERA also considers that the concerns expressed by WAMEU may be alleviated by setting service standard targets at the average level of performance achieved in AA3, such that rewards earned for service improvements will only be retained if performance is sustained in AA4.

Step-change adjustments

1908. The Australian Energy Regulator requires performance targets under the service target performance incentive schemes to be adjusted for expected reliability improvements to prevent the service provider from recovering the costs of delivering service quality improvements through the service incentive scheme that have already been approved in a revenue determination:

> In setting a target, the AER would also need to consider how to take into account service performance improvements already funded through a revenue determination (eg a capex or opex allowance), as rewarding a DNSP for such improvements through the service incentive mechanism would result in double recovery of these costs. This means that where a step change in performance has already been funded, this should be reflected in the target.[428]

1909. The Australian Energy Regulator also stipulates that adjusted service performance targets should reflect the level of performance actually funded by customers in the prior regulatory period. Where penalty or reward caps have been reached,

[428] Australian Energy Regulator, Electricity distribution network service providers Service target performance incentive scheme, FINAL, Version 5 (corrected), October 2015.

performance targets in the subsequent regulatory period should reflect the level of performance for which the service provider has been actually rewarded or penalised:

> STPIS caps distributors' maximum reward/penalty for improvement/decline in service levels. Once the actual service levels result in this cap being reached, the actual performance level should also be capped so that the distributor's performance target in future represents the financial reward/penalty funded by the customers. In particular, a distributor should not be rewarded for poor performance because of the financial cap protection mechanism under the STPIS.[429]

1910. Other network modifications proposed or undertaken by Western Power that are expected to affect service performance in the AA4 period include: amendment to the calculation of the major event day threshold; investment in the Kalbarri microgrid project, and; an adjustment for modifications to a system security protection scheme in the Eastern Goldfields that has negatively impacted transmission service performance.[430]

1911. The ERA has considered the following step-change adjustments to service standard targets in the AA4 period:

- Adjustments to service standard targets on the distribution network to account for the revised major event day threshold calculation method.
- Adjustments to the SAIDI and SAIFI Rural long performance targets to account for the improvement in service performance from the Kalbarri microgrid project.
- Adjustments to the loss of supply event frequency (greater than 1.0 system minutes) due to the installation of a new system security protection scheme.
- Where individual penalty caps or cumulative revenue-at-risk caps have been reached in the third access arrangement period.

Major event day threshold calculation method

1912. In the draft decision, the ERA approved Western Power's proposed revision to apply the Box-Cox method to transform daily unplanned SAIDI data for the purpose of calculating the major event day threshold.

1913. Western Power has adjusted historical data to reflect the revised method for removing interruptions that are excluded as major event days for the SAIDI, SAIFI and call centre performance measures. The effect of the adjustment is that fewer days will be excluded under the proposed method and service performance in the AA3 period would have been correspondingly lower.

1914. The ERA considers the adjustment to account for the revised method of determining the major event day threshold is consistent with the Access Code objective. The adjustments are shown in Table 177.

[429] Australian Energy Regulator, Issues paper, Reviewing the Service Target Performance Incentive Scheme and Establishing a new Distribution Reliability Measures Guidelines, Electricity distribution network service providers, January 2017, p. 32.

[430] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 166.

Kalbarri microgrid project

1915. Western Power proposed to adjust the SAIDI Rural long service standard target by 5.63 system minutes and the SAIFI Rural long service standard target by 0.06 interruptions to reflect improved performance expected to result from the investment in battery storage and the microgrid project in Kalbarri.

1916. In the draft decision, the ERA considered the proposed adjustments to be consistent with the Code objective and approved the proposal.

1917. Western Power did not revise its proposal to adjust SAIDI and SAIFI Rural long performance measures to account for the Kalbarri microgrid and battery storage project and no public submissions were received on this component of the draft decision.

1918. Consequently, the ERA maintains the position taken in the draft decision to approve the proposed adjustments to the SAIDI and SAIFI Rural long service performance targets due to the anticipated improvement in performance on the Kalbarri feeder.

New system security protection scheme on the transmission network

1919. Following the draft decision, Western Power reviewed the performance on the transmission network to account for a modification to the system security protection scheme implemented in February 2016 that would adversely affect the transmission performance measures.

1920. Western Power stated:

> 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.

1921. Western Power has determined that the effect of the system protection scheme, if it had been in place for the duration of AA3, would have resulted in eight additional interruption events being recorded in the loss of supply event frequency (>1.0 system minutes) performance measure. Western Power proposed to adjust the corresponding service standard target, from one event to two events.

1922. Technical advice provided to the ERA concluded the justification and magnitude of the proposed adjustment to the service standard target for the loss of supply event frequency performance measure to be reasonable:

- The information provided by WP indicates that the decision to modify the special protection scheme on the 220kV lines between Muja and Merredin is justified and this will result in an increased number of interruptions to the grid supply serving the Eastern Goldfields.
- Given there were 4 interruptions in 2017/18 with a SMI greater than 1.0 minutes, WP's proposal to increase LoSEF (>1 min) SSB from 4 to 6 appears reasonable. The consequential change in the SST from 1 to 2 is also reasonable.[431]

1923. The ERA considers Western Power's proposed amendment to the service standard target for the loss of supply event frequency (>1.0 system minutes) performance measure from one to two events for the AA4 period to be consistent with the Access Code objective.

Adjusting service standard targets where individual penalty and cumulative reward caps have been applied

1924. Section 3.2.1(a)(1B) of the service target performance incentive scheme for distribution network service providers, administered by the Australian Energy Regulator, requires performance targets to be adjusted to the extent that actual performance does not lie between upper and lower revenue-at-risk caps.[432]

1925. The adjustment ensures that a service provider is not rewarded with easier targets in a subsequent period where it has failed to meet a minimum service standard. Conversely, where a service provider has delivered service improvements in excess of a reward cap under a service incentive scheme, performance targets in the subsequent period would be adjusted to reflect the level of service performance that has been rewarded through the scheme:

> When a distributor's actual performance is much better or worse than the performance targets leading to the financial reward or penalty under the STPIS exceeding the revenue at risk cap under the scheme, its actual performance for the purpose of setting the performance targets for the subsequent period must be adjusted accordingly.
>
> This is to ensure that the distributor's performance target in future reflects the financial reward/penalty they received. In particular, a distributor should not be rewarded for poor performance because of the financial cap protection mechanism under the STPIS.[433]

1926. The service standard adjustment mechanism includes individual penalty caps on performance measures, set at the service standard benchmark level of performance, and cumulative penalty and reward caps on each of the distribution and transmission networks, set at the approved rate of revenue-at-risk. Consequently, the ERA has considered whether adjustments to the service standard target should be made for the AA4 period in the following circumstances:

- Where Western Power has applied a penalty cap where it has failed to meet the minimum level of service performance on an individual performance measure.

[431] Geoff Brown and Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018.

[432] Australian Energy Regulator, Draft, Electricity distribution network service providers, Service Target Performance Incentive Scheme, Version 2, December 2017.

[433] Australian Energy Regulator, Explanatory statement, Proposed amendment, Service Target Performance Incentive Scheme (STPIS), December 2017, p. 21.

- Where Western Power has achieved a cumulative reward (or penalty) cap on the distribution or transmission network.

1927. A distinction between the individual penalty cap and cumulative revenue-at-risk caps is that the individual penalty cap is based on actual performance not meeting a specified minimum standard or benchmark level of performance. Cumulative revenue-at-risk caps are determined as an implied valuation of service performance relative to a target, or expected, level of performance.

1928. Where an individual penalty cap has been applied, the ERA considers an adjustment to exclude the "unpenalised" performance component from the calculation of the service standard target in the subsequent regulatory period to be consistent with the Access Code objective. The adjustment ensures that Western Power has an incentive to rectify sub-benchmark performance and does not achieve a dual benefit by avoiding the cost of underperformance due to the capping of penalties, and applying a more lenient performance target in the subsequent regulatory period.

1929. Where performance has exceeded a cumulative revenue-at-risk cap, the AER's draft service target performance incentive scheme for distribution network service providers requires performance to be scaled back to the equivalent level of performance that would have been achieved at the revenue-at-risk cap. The performance target in the subsequent period reflects only the performance component for which the service provider had been rewarded or penalised.[434]

1930. The effect of the AER's required adjustment in the case where a service provider has exceeded a cumulative reward cap is that the service provider will be able to recover the unrewarded component of actual performance in the next regulatory period, if it were to maintain performance at an average levels in the prior period.

1931. Implicit in the adjustment required by the Australian Energy Regulator is the assumption that customers have benefitted from the provision of a level of service quality for which they would have been willing to pay, but for the application of a revenue-at-risk cap.

1932. Alternatively, if a service provider has exceeded a cumulative penalty cap, the service provider would continue to be penalised in the subsequent regulatory period if it were to maintain an average level performance equivalent to that achieved in the prior period.

1933. The ERA considers the adjustment required by the Australian Energy Regulator to be inconsistent with the purpose of the revenue-at-risk cap as a risk mitigation measure for the following reasons:

  - The purpose of the revenue-at-risk caps, as a component of the service standard adjustment mechanism, is to constrain investment and expenditure in service provision that exceeds a level of performance valued by customers, and avoid sudden and material tariff adjustments.
  - Reward rates are based on estimates or proxies for customers' willingness to pay for reliability improvements. The revenue-at-risk cap addresses the limitations of a constant marginal rewards schedule that would not otherwise

[434] Australian Energy Regulator, Explanatory statement, Proposed amendment, Service Target Performance Incentive Scheme (STPIS), December 2017, Appendix C.

accommodate the fact that, at a particular level of service performance, customers do not value improvements in service quality.

- Western Power's customer engagement program, undertaken in 2015, indicates that, in general, customers are unwilling to pay more for improved service quality.
- The AEMO's substantially revised estimates of values of customer reliability, completed in 2014, implies Western Power has continued to apply incentive rates based on outdated values of customer reliability throughout the third access arrangement period, which has been a significant factor in the accrual of excess rewards under the service standard adjustment mechanism.

1934. Consequently, the ERA does not consider an adjustment to service performance where Western Power has exceeded the cumulative reward cap in AA3 to be consistent with the Access Code objective.

1935. The cumulative adjustments to average service performance during AA3 are shown in Table 177, below, to derive service standard targets for the remainder of the AA4 period.

1936. In most cases, the required service standard targets are more stringent than those proposed by Western Power although, in all cases, Western Power has already achieved all target performance levels in the final year(s) of AA3, which are therefore both theoretically and practically achievable at existing levels of investment and expenditure.

Table 177 Average annual performance during the AA3 period and adjustments for the new major event day threshold (MEDT) method, capital expenditure and system protection measure (SPM), and service standard benchmark (SSB) penalty caps, to determine service standard targets for the remainder of the AA4 period

Performance measure	(A) AA3 average performance	(B) MEDT adjustment	(C) Capex and SPM adjustment	(D) SSB penalty cap adjustment	(E) AA4 service standard target
Distribution reliability performance measures					
System average interruption duration index (minutes)					
CBD	17.7	0.0	-	-	17.7
Urban	101.8	5.0	-	-	106.8
Rural short	175.8	12.8	-	-	188.6
Rural long	649.1	44.0	-5.63	-9.83	677.7
System average interruption frequency index (interruptions)					
CBD	0.12	0.00	-	-	0.12
Urban	1.06	0.03	-	-	1.09
Rural short	1.90	0.06	-	-	1.96
Rural long	4.45	0.20	-0.06	-0.30	4.29
Call centre performance (%)	92.1	-0.02	-	-	92.0
Transmission reliability performance measures					
Circuit availability (%)	98.5	-	-	-	98.5
Loss of supply event frequency (interruptions)					
>0.1 and ≤1.0 system mins.	16.6	-	-	-	17
>1.0 system minutes	1.0	-	1.0	-	2
Average outage duration (mins.)	860	-	-	-75.80	784

Required Amendment 40

Western Power must set service standard targets for the financial years from 2018/19 to 2021/22 at the average annual level of performance achieved in the third access arrangement period, adjusted for anticipated changes in service reliability and where individual penalty caps have been applied during the third access arrangement period, as shown in Table 177.

Use the value of customer reliability estimates from AEMO's 2014 study to set distribution reliability incentive rates

1937. Western Power proposed to apply values of customer reliability estimated from a review completed by AEMO in 2014 to set incentive rates for distribution reliability measures in the AA4 period.

1938. The draft decision required the removal of penalties and rewards from the service standard adjustment mechanism for the AA4 period and consequently did not approve the proposal to apply the value of customer reliability estimates derived from AEMO's 2014 review.

Western Power's revised proposal

1939. Western Power did not accept the required amendment to remove penalties and rewards from the service standard adjustment mechanism and maintained its proposal to use values derived from the review completed by AEMO to determine incentive rates for distribution reliability measures.

1940. Specifically, Western Power proposed values of reliability for residential customers in Western Australia based on proxy values estimated for South Australia, citing comparable climatic conditions, including extreme weather events, time of day energy use, and seasonal factors that influence energy consumption in each jurisdiction.[435]

1941. The values of customer reliability proposed by Western Power for the AA4 period are compared with those applied in AA3 in Table 178, below.

Table 178: Values of customer reliability applied by Western Power during the AA3 period and proposed for the AA4 period ($ per kWh, 30 June 2017)

Feeder	AA3	AA4 proposed	% change
CBD	113.7	51.0	-55%
Urban	73.4	43.2	-42%
Rural short	71.1	41.9	-42%
Rural long	80.8	43.1	-47%

Further submissions

1942. Energy Networks Australia supported Western Power's proposal to apply values of customer reliability using AEMO's study completed in 2014 to set incentive rates for the service standard adjustment mechanism in the fourth access arrangement period, consistent with industry practice:

> Western Power has proposed distribution incentive rates aligned with the value of customer reliability, based on the most recent value of customer reliability study by the Australian Energy Market Operator in 2014 adjusted to apply for the Western Power

[435] Western Power, *Access arrangement information, Attachment 6.4 Estimation of the value of customer reliability for Western Power's network*, 2 October 2017, p. 5.

> Network. In relation to transmission network reliability and call centre incentive rates, Western Power applied a percentage of its revenue at risk consistent with that in the previous access arrangement period. The methodology for calculating the incentive rates is also consistent with industry practice such as the Australian Energy Regulator's service target performance incentive scheme.[436]

1943. WAMEU questioned whether the rewards earned by Western Power under the service standard adjustment mechanism in AA3 accurately reflected customers' value of service reliability, suggesting the optimal level of service performance has been attained, or exceeded:

> At what point does the cost of the improved service reach the value that consumers place on this improvement? Maintenance of bonuses for improved services merely add to the prices of the WP services. WAMEU notes that the ERA does attempt to assess the value consumers place on this increased reliability, but it is now getting to the point where consumers would prefer to see a reduction in prices and remain with current (even slightly lower) service levels.[437]

Considerations of the ERA

1944. Values of customer reliability estimates represent the average value of service reliability to classes of customers in dollars per kilowatt-hour. The values are applied in the service standard adjustment mechanism to link service performance outcomes on the distribution network with a target revenue adjustment (net penalty or reward) in the subsequent regulatory period.

1945. Western Power proposed to apply values of customer reliability derived from AEMO's review of the National Electricity Market, completed in 2014. Western Power stated that the values derived from that study reflect accepted industry practice and would be consistent with the Access Code objective by incentivising economically efficient investment.[438]

1946. Since Western Australian customers were not surveyed AEMO, Western Power used values estimated for South Australia as a proxy jurisdiction to estimate values of customer reliability in Western Australia.

1947. The following matters are considered to determine the consistency of the proposal to apply values of customer reliability derived from AEMO's review with the Access Code:

- The accuracy and robustness of the review completed by AEMO in 2014.
- The choice of South Australia as a proxy for Western Australian residential customers.
- The reasonableness and application of the rates proposed by Western Power.

[436] Energy Networks Australia, submission on the draft decision, 14 June 2018.

[437] Western Australia Major Energy Users, submission to draft decision on Western Power's fourth access arrangement, June 2018, p. 55.

[438] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 202, para. 1189.

- Mid-period review of incentive rates.

Australian Energy Market Operator's review

1948. Prior to AEMO's review in 2014, values of customer reliability had been estimated on a jurisdictional basis, resulting in substantial differences in estimated values that were not directly comparable, particularly between commercial customers.[439]

1949. In 2013, the Productivity Commission reported that historical estimates of values of customer reliability in Australia were generally high by international standards, noting "several major flaws" in previous studies that tended to produce upwardly biased estimates.[440] WAMEU expressed a similar concern in their submission to the review of Western Power's AA3 proposal:

> The WAMEU is very concerned at the magnitude of this value and its associate Major Energy Users (MEU) has raised similar concerns directly with AEMO. The MEU points to the way the Australian Energy Market Operator assessed value of VCR has increased in real terms over the past decade whereas similar values used overseas are much lower and have varied little with time. This raises the concern that the AEMO developed VCR maybe considerably overstated. [441]

1950. AEMO's review, completed in 2014, was the first comprehensive cross-jurisdictional examination of values of reliability in the National Electricity Market and sought to address flaws identified in earlier studies and in the development of the review, including survey anomalies, biases, omissions, and limitations.[442,443]

1951. The results of the review have been applied in regulatory determinations and reliability standard setting by the Australian Energy Regulator, AEMO, and the Independent Pricing and Regulatory Tribunal in New South Wales. Findings of the review included:

- Residential values of customer reliability between National Electricity Market jurisdictions have not changed substantially since 2007/08.

- Higher values of customer reliability among business customers, consistent with other Australian and international studies.

- A majority of customers are satisfied with existing levels of reliability.[444]

1952. Identified limitations of the values estimated by AEMO in 2014, include:

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[439] Productivity Commission, Electricity Network Regulatory Frameworks, Productivity Commission Inquiry Report, Volume 2, No. 62, 9 April 2013, p. 537.

[440] Productivity Commission, Electricity Network Regulatory Frameworks, Productivity Commission Inquiry Report, Volume 2, No. 62, 9 April 2013, p. 538.

[441] Western Australian Major Energy Users, submission to draft decision on Wester Power's third access arrangement, November 2011, p. 87.

[442] Productivity Commission, Submission DR100 – Australian Energy Market Operator – Electricity Network Regulation Public Enquiry, 15 January 2013.

[443] Australian Energy Market Operator, Value of Customer Reliability Issues Paper, 11 March 2013.

[444] Australian Energy Market Operator, Value of Customer Reliability Final Report, September 2014, p. 1.

- A wide confidence range in the estimated values of +/- 30 per cent, typical of choice modelling and contingent valuation methods.[445]

- Limited application of the estimated values of customer reliability to high impact or prolonged outages, or intra-regional planning.[446]

- Inherent limitations in the aggregation of customer values to derive an average estimate, which obscures the range of values ascribed by individual customers or sub-groups.

- Annual indexation of the estimated values to the consumer price index does not necessarily reflect the changing composition of customer segments or preferences.[447]

1953. Major Energy Users Inc. also questioned whether the annual indexation of estimated values implied a level of precision that was not supported by the analysis or reflective of changing customer preferences for network reliability:

> Because the VCR is only an approximation, it makes little sense that the value should be adjusted using an annual inflator to retain its "real" value. To imply such exactitude to the value implies that the answer obtained from the survey has a degree of exactness that is simply not there.
>
> There is little doubt that over time the VCR will change and the assumption made by proposing to use a cost price inflator is that it will continue to increase. In contrast, with the changing electricity market that has been evident for the past 3-5 years and the potential for new technology and the changed uses of electricity that have been seen and are forecast to occur, means that the VCR could conceivably fall over time… Whether these falls were the result of better surveying techniques, changing consumer views, changes in the market or a combination of all is uncertain – what is certain is over time there have been quite dramatic shifts in the assessed VCRs and that in this recent review the value has fallen considerably.[448]

1954. AEMO ultimately considered there to be "no justification" for allowing estimated values of customer reliability to fall in real terms.[449]

1955. Major Energy Users Inc. was, however, supportive of the "thorough and comprehensive process" adopted by AEMO in the development of the value of customer reliability estimates in 2014:

> The MEU was very active in the development of the AEMO approach to developing VCRs in 2014 and considers that the AEMO process reflects very good practice in achieving goals for VCR.
>
> …
>
> As noted above, the MEU considers that the AEMO process used in 2014 was good practice and this should be the starting point for the AER in the future – AEMO carried

[445] Australian Energy Market Operator, Value of Customer Reliability Final Report, September 2014, p. 31.

[446] Australian Energy Market Operator, Value of Customer Reliability Application Guide, December 2014.

[447] Essential Services Commission of South Australia, SA Power Networks reliability standards review, Draft decision, August 2018, p. 57.

[448] Major Energy Users Inc., submission to VCR Applications Guide, 20 October 2014.

[449] Australian Energy Market Operator, Value of Customer Reliability Application Guide, December 2014, p. 30.

> out significant consultation as it developed its process and this work should not be lost.[450]

1956. In considering the broad context and implied precision of the estimated values of customer reliability, the Productivity Commission emphasised that the inherent limitations of survey-based valuation methods should not preclude the collection of empirical evidence and application of estimated values in network planning and reliability standard setting:

> The key point is that, estimated or not, for any given level of reliability, there is a corresponding value that customers place on it. At the very least, the valuation implicit in any mandated standard should be made explicit, and assessed for its reasonableness using empirical evidence.[451]

1957. An earlier review prepared for the Queensland Competition Authority also suggested that completely accurate estimates of values of customer reliability are not necessary for an incentive scheme to achieve the objective of maintaining or improving service performance, providing the reward or penalty schedule fell between the distributor's marginal cost of service provision and customers' marginal willingness to pay for service quality:

> Setting an appropriate rate for rewards and penalties is one of the most difficult elements of introducing a service quality incentives scheme. Ideally the schedule of rewards and penalties should mimic customers' marginal willingness to pay for service quality… However, determining what customers' marginal willingness to pay schedules really look like is notoriously difficult. Customers often have difficulty valuing a hypothetical product they have not experienced before and there are numerous incentives for customers to misrepresent their preferences. Distributors also have an incentive to overstate their true costs of improving service quality and exploit the information asymmetry the regulator faces.
>
> Completely accurate estimates of customers' marginal willingness to pay and the distributor's marginal costs are not, however, necessary for the scheme to lead to significant steps towards the optimal level of service quality. As long as the reward and penalty schedule lies between the distributor's marginal cost schedule and the customer marginal willingness to pay schedule then improvements will result.[452]

1958. Since minor variations in the estimated values of customer reliability will be amplified when aggregated and applied to network service performance, the ERA considers compliance with the Access Code objective requires estimated values of customer reliability to be prudent and cautious. The estimates derived by AEMO in 2014, escalated for changes in the Consumer Price Index, represent the most recent, comprehensive and robust values of service reliability for electricity consumers in the National Electricity Market.

South Australia as a proxy for Western Australian customers

1959. Western Power considered the following factors in selecting South Australia as the closest jurisdictional comparator in the National Electricity Market to Western Australia:

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[450] Major Energy Users Inc., submission to Consultation Paper on Establishing values of customer reliability (VCR), 7 June 2018.

[451] Productivity Commission, Electricity Network Regulatory Frameworks, Productivity Commission Inquiry Report, Volume 2, No. 62, 9 April 2013, p. 541.

[452] Meyrick and Associates, Electricity Service Quality Incentives Scoping Paper, Prepared for Queensland Competition Authority, 4 July 2002.

- The proportion of household expenditure on gas and electricity, based on the Australian Bureau of Statistics' Household Energy Consumption Survey published in 2013, including household solar panel installation rates.

- Climatic similarities, specifically the average number of extreme hot days as an indicator of peak electricity demand.

1960. Household income and composition was also considered, although AEMO's review suggested household income was not a significant contributing factor to residential values of customer reliability.

1961. Residential electricity prices were not considered because customers across the National Electricity Market were generally satisfied with existing levels of reliability, despite price differences.[453]

1962. Western Power's proposed values of customer reliability for AA4 were derived by:

- Using Western Power historical interruption data to calculate interruption probabilities for each customer class based upon time of day, weekday and season.
- Multiplying the probability of each interruption by the corresponding estimate derived from the proxy jurisdiction in the National Electricity Market.[454]

1963. Western Power's consultant, Synergies Economic Consulting, identified the following limitations in the data used to derive estimated values of customer reliability, although considered the resulting values to be sufficiently robust to be applied by Western Power in the fourth access arrangement period:

- unavailability of agricultural customer outage data

- unclassified outage data

- unavailability of peak demand data, requiring use of electricity consumption data.[455]

1964. The ERA also considered the recency of the estimated value of customer reliability in South Australia, noting the Essential Services Commission of South Australia amended the aggregated estimate (from $38,090 per MWh in March 2014, to $40,620 per MWh in September 2017), to reflect cumulative Consumer Price Index adjustments and the changing composition of the South Australian economy.[456]

1965. The ERA considers the Essential Services Commission's adjustment to be within the confidence range reported by AEMO and consequently not material.

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[453] Western Power, *Access arrangement information, Attachment 6.4 Estimation of the value of customer reliability for Western Power's network*, 2 October 2017, p. 5.

[454] Western Power, *Access arrangement information, Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 102, para. 377.

[455] Western Power, *Access arrangement information, Attachment 6.4 Estimation of the value of customer reliability for Western Power's network*, 2 October 2017, p. 47.

[456] Essential Services Commission of South Australia, SA Power Networks reliability standards review, Draft decision, August 2018, p. 62.

1966. AEMO's estimated values of customer reliability for non-residential (business) customers are not differentiated by jurisdiction.[457] Consequently, Western Power has adopted the aggregate non-residential values of customer reliability estimated for each class of non-residential customers in the National Electricity Market, escalated for changes in the Consumer Price Index to June 2017.

1967. In conclusion, the ERA considers:

- The factors nominated by Western Power to select South Australia as the closest comparator jurisdiction in the National Electricity Market are reasonable and have not materially changed to the extent that an alternative jurisdiction would be considered a more suitable proxy.

- The indexed values of customer reliability proposed by Western Power should not be amended to reflect changes in the composition of the South Australia economy.

Reasonableness of estimates

1968. The ERA assessed the reasonableness of the values of customer reliability proposed by Western Power against the following factors:

- The magnitude of the adjustment to the proposed values of customer reliability.

- The apportioned weightings of the value of customer reliability to SAIDI and SAIFI to determine incentive rates in the service standard adjustment mechanism.

Magnitude of adjustment

1969. Given the magnitude of the proposed adjustments to the values of customer reliability, the ERA considered whether the application of an asymmetric or graduated incentive scheme would be consistent with the Access Code objective.

1970. The reduction in the proposed values of customer reliability effectively de-risks the service standard adjustment mechanism for Western Power such that penalties for service performance deterioration in the AA4 period will be applied at a lower rate than rewards had been earned for an equivalent reliability improvement in the third access arrangement period.

1971. Similarly, a lower reward rate in the AA4 period reduces the incentive to restore service performance that may have declined in AA3.

1972. AEMO previously considered whether new values of customer reliability should be transitioned gradually, although decided that the proposal was without merit:

> AEMO recognises that large step changes in VCR value from one survey to the next may reduce investor certainty and create planning challenges… While changes from one survey to another are likely to reflect changes in consumer sentiment, differences in survey methodology or sampling error can also contribute to variations in the value.
>
> Nonetheless, AEMO does not consider merit in applying smoothing techniques to VCR values to dampen any step-change impact... Smoothing the transition between VCR

[457] Australian Energy Market Operator, Value of Customer Reliability Final Report, September 2014.

survey results will distort and delay any network planning response to these changes in consumer sentiment… By using the most up-to-date forecasts, network planners are making decisions on efficient, long-term infrastructure investment based on the latest information available, to ultimately benefit electricity customers.[458]

1973. The Australian Energy Regulator also considered the application of an asymmetrical financial incentive in the service target performance incentive scheme for distribution network service providers, due to the typically asymmetric nature of service reliability and excess network capacity that had been funded by customers.[459] Stakeholders did not support the proposal, citing the Australian Energy Regulator's previous observation that a symmetrical scheme more closely mimicked a competitive market.[460] The service target performance incentive scheme was not amended to permit the application of asymmetric rewards and penalties.

1974. Although the ERA considers the application of differential values of customer reliability may align more closely with theoretical values of customer reliability at different levels of service performance, the complexity and implied precision of a mechanism comprising differential incentive rates is not supported by available data.

Apportionment of value of customer reliability weightings

1975. The ERA also considered the apportionment of the value of customer reliability in the calculation of SAIDI and SAIFI incentive rates to assess the reasonableness of the values proposed by Western Power.

1976. The incentive rates for SAIDI and SAIFI in each feeder category are calculated by apportioning the value of customer reliability, as below:

$$IR_f^{SAIDI} = VCR_f * \left(1 - \frac{1}{1 + w_f}\right) * C_f * \frac{10^6}{MPY}$$

$$IR_f^{SAIFI} = VCR_f * \left(\frac{1}{1 + w_f}\right) * \left(\frac{SST_f^{SAIDI}}{SST_f^{SAIFI}}\right) * C_f * \frac{10^6}{MPY}$$

Where:

IR_f^{SAIDI}	is the incentive rate (penalty or reward) for SAIDI feeder category (f) in dollars per minute
IR_f^{SAIFI}	is the incentive rate (penalty or reward) for SAIFI feeder category (f) in dollars per 0.01 interruptions
f	refers to the feeder categories: CBD, Urban, Rural short and Rural long
VCR_f	is the CPI-adjusted value of customer reliability for feeder category (f) in dollars per kWh

[458] Australian Energy Market Operator, Value of Customer Reliability – Application Guide, Final Report, September 2014, p. 23.

[459] Australian Energy Regulator, Issues Paper, Reviewing the Service Target Performance Incentive Scheme and Establishing new Distribution Reliability Measures Guidelines, Electricity distribution network service providers, January 2017, p. 34.

[460] Australian Energy Regulator, Explanatory Statement, Proposed amendment Service Target Performance Incentive Scheme (STPIS), December 2017, p. 25.

w_f	is the apportioned value of customer reliability weighting between SAIDI and SAIFI for feeder category (f)
C_f	is the average annual energy consumption for feeder category (f) in GWh per year
MPY	is the average number of minutes per year (365.25 * 24 * 60)
SST_f^{SAIDI}	is the SAIDI service standard target for feeder category (f)
SST_f^{SAIFI}	is the SAIFI service standard target for feeder category (f)

1977. In reviewing the service target performance incentive scheme for distribution network service providers, the Australian Energy Regulator observed that distributors in the National Electricity Market had typically achieved disproportionate improvements in reducing the frequency of outages (SAIFI) relative to the duration of outages (SAIDI).[461] This effect was observed in the increasing duration of the Customer Average Interruption Duration Index (CAIDI) among distributors in the National Electricity Market.

1978. CAIDI measures the average restoration time per customer and is calculated as the ratio of SAIDI to SAIFI. A progressive deterioration (increase) in CAIDI performance is also observed on the Western Power Network during AA3 for all feeder categories except CBD, which is highly variable (Table 179).

Table 179 Customer Average Interruption Duration Index (CAIDI) by feeder category on the Western Power Network and estimated overall trend change during the AA3 period, from 2012/13 to 2016/17

Feeder	2012/13	2013/14	2014/15	2015/16	2016/17	Estimated overall trend change
CBD	253.3	91.5	154.1	226.0	125.5	-20%
Urban	88.5	95.0	94.5	100.3	102.4	14%
Rural short	83.6	93.6	92.2	96.2	99.8	16%
Rural long	139.6	135.3	153.6	146.0	158.5	13%

1979. The Australian Energy Regulator considered the apportionment of the value of customer reliability (w_f) between SAIDI and SAIFI had biased the incentive for network service providers to invest in capital projects that reduce the frequency of interruptions, rather than outlay operating expenditure to improve supply restoration time, and proposed revised weightings in the draft service target performance incentive scheme (

[461] Australian Energy Regulator, Issues Paper, Reviewing the Service Target Performance Incentive Scheme and Establishing new Distribution Reliability Measures Guidelines, Electricity distribution network service providers, January 2017, p. 16.

1980. Table 180):

> The combined effect of improvements to SAIFI relative to SAIDI is that the average supply restoration time, CAIDI, is getting longer.
>
> We believe at least part of this increase in supply restoration time is due to the current STPIS design of an approximate 50/50 allocation of the incentive to SAIDI and SAIFI measures.
>
> Our draft position is to change the ratio of the SAIDI/SAIFI incentives from 50/50 to 60/40 based on the allocation of energy value.[462]

1981. The Australian Energy Regulator noted that the previously applied ratio had assumed that customers valued a reduction in the frequency of interruptions more than the duration of the outage.[463] In contrast, and consistent with results across the National Electricity Market, Western Power's customers have expressed more concern with the duration, rather than the frequency, of outages:

> Approximately three-quarters (74%) of customers thought that the duration of the outages they experience were 'about right' or relatively short. A larger proportion of customers (86%) thought the number of outages they experience was 'reasonable' or better than they would consider acceptable. This suggests customers are more likely to view the frequency of outages as more acceptable than the duration.[464]

Table 180: Previous and revised weightings of values of customer reliability rates to SAIDI and SAIFI in the service target performance incentive scheme[465]

Feeder	Previous weighting	Revised weighting
CBD	1.13	1.5
Urban	0.97	1.5
Rural short	0.92	1.5
Rural long	0.92	1.5

1982. The ERA considers the revised value of customer reliability weightings proposed by the Australian Energy Regulator to be consistent with the Access Code objective in setting incentive rates for distribution reliability measures in the service standard adjustment mechanism for Western Power's AA4 period.

1983. The revised incentive rates to be applied by Western Power for the years from 2018/19 to 2021/22 are shown in Table 183, below.

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462 Australian Energy Regulator, *Explanatory statement Proposed amendment Service Target Performance Incentive Scheme (STPIS)*, December 2017, p. 10.

463 Australian Energy Regulator, Issues Paper, Reviewing the Service Target Performance Incentive Scheme and Establishing new Distribution Reliability Measures Guidelines, Electricity distribution network service providers, January 2017, p. 16.

464 Western Power, *Access arrangement information, Attachment 4.1 Customer Insights Report,* 2 October 2017, p. 32.

465 Australian Energy Regulator, *Draft Electricity distribution network service providers Service target performance incentive scheme, Version 2*, December 2017, p. 11, Table 1.

1984. In conclusion:

- The revised values of customer reliability published by AEMO in 2014 are the most current and comprehensive estimates of the value of service reliability in the National Electricity Market.
- The South Australian residential customer segment remains the most suitable proxy jurisdiction for Western Australian residential customers.
- Western Power must apply incentive rates to SAIDI and SAIFI symmetrically.
- Western Power must apportion the values of customer reliability between SAIDI and SAIFI incentive rates at the new ratios listed in
- Table 180.

Scope for mid-period review

1985. The Australian Energy Regulator was assigned responsibility for calculating values of customer reliability estimates in the National Electricity Market in July 2018.[466] The rule change requires the Australian Energy Regulator to produce annually revised estimates of values of customer reliability based on customer surveys completed every five years. The first estimates must be published by December 2019.

1986. Section 4.38 of the Access Code provides scope for the ERA to vary the price control, including the service standard adjustment mechanism, under particular circumstances before the next revisions commencement date if the advantages of making the variation are considered to outweigh the disadvantages.

1987. The ERA will consider the materiality of any unforeseen variation in the values of customer reliability published by the Australian Energy Regulator to determine whether the advantages of varying the service standards adjustment mechanism before the end of the access arrangement period exceed the disadvantages of making a variation.

Required Amendment 41

Western Power must apply the revised weightings of values of customer reliability to SAIDI and SAIFI incentive rates listed in

Table 180.

[466] Australian Energy Market Commission, Rule Determination, National Electricity Amendment (Establishing Values of Customer Reliability) Rule 2018, 5 July 2018.

Updated allocation and caps on revenue-at-risk

1989. Western Power proposed to apply a cap on revenue-at-risk at 5.0 per cent of target revenue on the distribution network and 1.0 per cent of target revenue on the transmission network.

1990. Western Power also proposed to remove the system minutes interrupted service standard benchmark and targets for the fourth access arrangement period and allocate the revenue-at-risk on the transmission network to the remaining performance measures, including circuit availability, average outage duration, and loss of supply event frequency (>0.1 and ≤1.0 minutes, and >1.0 minutes).

1991. The draft decision required Western Power to remove rewards and penalties and reinstate the system minutes interrupted (radial) performance measure in the service standard adjustment mechanism for the AA4 period. The ERA did not approve the proposal to reallocate revenue-at-risk to account for the removal of system minutes interrupted and target revenue in the AA4 period.

Western Power's revised proposal

1992. Western Power did not accept the draft decision to remove rewards and penalties from the service standard adjustment mechanism in the AA4 period.

1993. Western Power did accept the draft decision to reinstate the system minutes interrupted (radial networks) performance measure, although did not include service standard targets and an allocation of revenue-at-risk to the performance measure in the revised proposal.

1994. Western Power maintained its proposal to cap revenue-at-risk at 5.0 per cent of target revenue on the distribution network and 1.0 per cent of target revenue on the transmission network:

> 1193. Western Power has proposed a cap of five per cent of distribution revenue at risk for the distribution measures. This is [in] line with the current national guideline on the revenue at risk for distribution network service providers and is less than caps that have been applied previously…
>
> 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, which is 1.25 per cent on the service component.[467]

Further submissions

1995. No further submissions were received that referenced the proposed allocation or magnitude of the revenue-at-risk caps proposed by Western Power.

Considerations of the ERA

1996. The ERA has considered the following matters in determining the consistency of Western Power's proposed revenue-at-risk caps with the Access Code:

[467] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 203, paras. 1193-4.

- Whether revenue-at-risk should be capped in the fourth access arrangement period.
- The symmetry and level of revenue-at-risk caps.
- The allocation of revenue-at-risk on the transmission network.

Whether revenue-at-risk should be capped

1997. In its revised proposal, Western Power suggested the cap on revenue-at-risk in the service standard adjustment mechanism restricted efficient investment in service performance:

> 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.[468]

1998. Western Power also cited a submission from AusNet Services to the Australian Energy Regulator in 2009, which claimed the reward cap penalised customers by preventing them from receiving efficient reliability improvements.[469]

1999. Western Power also stated that a consequence of having reached the reward cap in consecutive years during AA3 was that customers would benefit from service performance improvements at a higher value than they would have paid:

> 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.[470]

2000. Each of Western Power’s statements, above, is inconsistent with the purpose of the cap on revenue-at-risk as a risk mitigation measure. The Australian Energy Regulator has stated that the revenue-at-risk caps provided certainty for service providers and customers under the service target performance incentive scheme:

> A key element of the incentive properties of a STPIS is the overall level of revenue that is at risk from the potential rewards and penalties provided for under the scheme. Placing a financial limit on the revenue at risk provides certainty to a DNSP of the maximum penalty that it might receive and, correspondingly, also provides a maximum reward that customers might pay for.[471]

2001. In its determination on the submission cited by Western Power, above, the Australian Energy Regulator accepted the circumstantial support for the service provider’s position that the efficient level of service performance was beyond the level represented at the default reward cap, but did not approve the proposal to implement an uncapped scheme. The Australian Energy Regulator considered the purpose of the cap – to protect customers from abrupt and substantial increases in service costs – to have more import than the immediate implementation of an efficient level of

[468] Western Power, Revised AA4 proposal, Response to the ERA’s draft decision, 14 June 2018, p. 203, paras. 1191.

[469] Western Power, Revised AA4 proposal, Response to the ERA’s draft decision, 14 June 2018, p. 203, paras. 1191.

[470] Western Power, Revised AA4 proposal, Response to the ERA’s draft decision, 14 June 2018, p. 203, paras. 1192.

[471] Australian Energy Regulator, Explanatory statement and discussion paper, Proposed Electricity distribution network service providers service target performance incentive scheme, April 2008, p. 7.

service performance, and sought to encourage a "more measured reliability investment program":

> For these reasons and having regard to the objectives of the STPIS, the AER does not consider an uncapped scheme to be appropriate as an uncapped scheme places unnecessary risk on the future tariffs of customers and the revenues of a DNSP, relative to the benefits which consumers may derive from removing the cap.[472]

2002. Western Power's statements, above, are also inconsistent with the basis for reward payments under the service standard adjustment mechanism. Incentive rates derived from estimated values of customer reliability represent customers' willingness to pay for incremental service performance, or to avoid service decrements.

2003. To meet its objectives, a service incentive scheme should align a reward schedule with customers' marginal willingness to pay for service improvement, such that the service provider's marginal cost of service provision equals the marginal reward at the efficient level of service performance.

2004. Implicit in the scheme is the declining value of customers' marginal willingness to pay for service improvement such that, at a particular level of service quality, customers are unwilling to pay the cost of additional service improvements.

2005. Western Power has acknowledged the declining marginal value of service performance as service performance improves, citing its expert report:

> 1196. ACIL Allen conducted a study into the service performance and resulting rewards over time within the Victorian regulatory framework. 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 over time. Therefore the rewards available under the schemes also reduce as service reaches an equilibrium with customers' expectations.[473]

2006. The revenue-at-risk caps, therefore, provide safeguards in the case that the constant marginal rewards schedule does not align with an efficient level of service performance, and implicitly acknowledge that, at a particular level of service performance, customers' marginal willingness to pay for a higher standard of service quality reduces to nil.

2007. Western Power's service performance in the AA3 period, having reached the upper revenue-at-risk (reward) cap on both distribution and transmission networks in concurrent and consecutive periods, suggests either:

- The efficient levels of service quality on Western Power's networks exceeded the level of performance represented at the reward caps in the AA3 period.

  or

- Western Power has benefitted from a rewards schedule that was inefficiently structured to Western Power's advantage.

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[472] Australian Energy Regulator, Draft decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015, June 2010, pp. 638-9.

[473] Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 203, paras. 1196.

2008. The explanation that the efficient levels of service performance on Western Power's networks are beyond the levels of performance represented at the revenue-at-risk caps cannot be disproven without empirical evidence. The following considerations, however, suggest this explanation is unsupported:

- Western Power's customer research for the AA3 period, completed in 2010, found that, "on average, customers were satisfied with the current level of reliability."[474]

- Similarly, Western Power's customer engagement program undertaken in 2015 for its AA4 proposal, concluded that "[c]ustomers have told us they are generally satisfied with current levels of performance, and do not necessarily want Western Power to invest to improve service."[475]

- WACOSS questioned whether the incentive payments under the service standard adjustment mechanism had exceeded customer valuations of service quality:

> Service standards are a critical driver of costs, with higher service standards incentivising utilities to lift performance (and increase costs). This may lift service standards above the point where customers are willing to pay for improvements in service.[476]

- WAMEU also questioned whether the rewards schedule in the AA3 period exceeded customer valuations of service reliability:

> At what point does the cost of the improved service reach the value that consumers place on this improvement? Maintenance of bonuses for improved services merely add to the prices of the WP services. WAMEU notes that the ERA does attempt to assess the value consumers place on this increased reliability, but it is now getting to the point where consumers would prefer to see a reduction in prices and remain with current (even slightly lower) service levels.[477]

2009. The factors below, however, support the explanation that the service standard adjustment mechanism in the AA3 period was inefficiently structured to Western Power's advantage:

- Western Power continued to apply outdated and overestimated values of customer reliability throughout the AA3 period, following the publication of revised estimates by AEMO in 2014.

- Biased service standard targets in the AA3 period rewarded Western Power by default at the average level of service performance achieved in the AA2 period.

[474] Western Power, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 100.

[475] Western Power, Access Arrangement Information, Access arrangement revisions for the fourth access arrangement period, 2 October 2017, p. 88, para. 298.

[476] Western Australia Council of Social Service, AA4 Access Arrangement Submission 2017, 11 December 2017.

[477] Western Australia Major Energy Users, Response to the ERA Draft Decision, May 2018, p. 55.

- Western Power has not identified specific programs, capital expenditure, or external factors to explain the substantial and consistent improvement in service performance achieved throughout the AA3 period as an anomaly. Western Power had stated in its access arrangement information for AA3 that it had not included any forecast expenditure for performance improvements in the AA3 period:

> The expected level of performance for each service standard benchmark detailed under the SSAM will remain the same throughout the AA3 period. This is because no investment in performance improvements has been included in the AA3 expenditure forecasts.[478]

2010. In either case, the ERA considers the revenue-at-risk caps are a necessary risk mitigation measure that promote efficient investment where market information is imperfect and disparate.

Symmetry and level of revenue-at-risk caps

2011. The ERA considered the consistency of symmetrical revenue-at-risk caps with the Code objective.

2012. The Australian Energy Regulator has recently considered whether the service target performance incentive scheme for distribution network service providers in the National Electricity Market should continue to operate symmetrically.[479] The Australian Energy Regulator cited a submission from the Energy Users Association of Australia to a previous regulatory determination, which sought to implement an asymmetrical scheme to account for excess capacity that customers have already paid for, and to balance the risks to customers and service providers.

2013. In the draft amendment, the Australian Energy Regulator noted that the service target performance incentive scheme specifies a symmetric scheme and that all submissions from stakeholders sought to continue to apply the scheme symmetrically.[480]

2014. The ERA, however, considers the application of symmetrical revenue-at-risk caps to be inconsistent with the Access Code for the following reasons:

- The operation of the service standard benchmarks as penalty caps on individual performance measures already imposes an asymmetric reward and penalty structure on service performance under the service standard adjustment mechanism.

- Incentive rates for service performance on the transmission network are asymmetric.

- An asymmetric reward and penalty structure is empirically consistent.

2015. The disparity, or non-linearity, between customers' willingness to pay for service improvement and willingness to accept compensation for loss of service quality is

[478] Western Power, Access Arrangement Information for 1 July 2012 to 30 June 2017, September 2011, p. 96.

[479] Australian Energy Regulator, Issues paper, Reviewing the Service Target Performance Incentive Scheme and Establishing a new Distribution Reliability Measures Guidelines, January 2017, p. 34.

[480] Australian Energy Regulator, Explanatory statement, Proposed amendment, Service Target Performance Incentive Scheme (STPIS), December 2017, p. 25.

extensively documented in choice modelling literature, for example, and has been attributed to psychological factors (loss aversion), relative income, and the availability of substitute products or services:

> Asymmetry in willingness to pay (WTP) and willingness to accept (WTA) is one of the most documented phenomena in empirical literature. The basic finding is that while standard (Hicksian) economic theory allows for a small difference between WTP for a unit gain and WTA for a unit loss…, numerous empirical investigations have observed discrepancies which appear significantly larger than predicted in theory, with losses being valued substantially more than gains. Indeed as documented…, the empirical evidence is pervasive and gain–loss effects have been observed for a wide variety of economic goods. This includes goods traded in formal markets as well as commodities that are non-market and/or public good in nature, in real, hypothetical and experimental settings. In particular, the disparity in terms of the ratio of WTP to WTA is found to increase the further the good is from 'an ordinary private good'.[481]

2016. Different customer valuations of service improvements and service decrements have also been documented as a major limitation on the structure of incentive schemes in electricity service provision:

> In Norway and Italy the structure of the incentive scheme is symmetric around the performance standard and, thus, the incentive rate had to be the same for both rewards and penalties. By contrast, an extensive spread was observed between WTP and WTA (WTA was 4 to 7 times higher than WTP). Given these constraints, regulators have chosen incentive rates within a close range of the average of the WTP and WTA values. In particular, they have focused on the WTP and WTA values that resulted from the most representative interruption scenario (i.e. the scenario with an average interruption duration that coincided with the average SAIDI). Indeed, the large difference between WTP and WTA is one of the major problems with contingent valuation analysis.[482]

2017. Surveys in the National Electricity Market have also reported disparate valuations between customers' willingness to pay for service improvements and willingness to accept compensation for service degradation:

> It might be expected that the WTP and WTA approaches would provide similar results – that is, that customers' willingness to pay for a reliability improvement would be exactly the same their willingness to be compensated for an equivalent reliability degradation. However, instances where both approaches have been applied to the same service issue indicate that this is not the case. Rather, the results indicate that customers tend to give higher values for how much they would need to be compensated for a service degradation than they say they would be willing to pay for an equal improvement in service. This provides an insight into how the results of each type of approach should be interpreted, and highlights the importance of selecting the more appropriate approach for any particular survey undertaking. For example, a survey seeking to design an interruptibility program to defer network augmentation would probably provide a better estimate of customers' participation requirements by using a WTA approach. Valuation of a network augmentation, by contrast, might be more closely approximated by a WTP approach.[483]

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[481] Bruno Lanz, Allan Provins, Ian J. Bateman, Riccardo Scarpa, Ken Willis and Ece Ozdemiroglu, Investigating Willing to Pay–Willingness to Accept Assymetry in Choice Experiments, in Stephane Hess and Andrew Daly (eds.), Choice modelling: the state-of-the-art and the state-of-practice, Proceedings from the Inaugural International Choice Modelling Conference, Emerald Group Publishing, 2010, pp. 517-8.

[482] Elena Fumagalli, Luca Lo Shiavo, and Florence Delstre, Service Quality Regulation in Electricity Distribution and Retail, Springer, 2007, p. 135.

[483] Oakley Greenwood, Valuing Reliability in the National Electricity Market, Final Report, March 2011, p. 8.

2018. Consequently, the ERA considers asymmetric revenue-at-risk caps to be consistent with Code objective.

2019. Western Power stated in its revised proposal that the proposed revenue-at-risk caps, being 5.0 per cent of target revenue on the distribution network and 1.0 per cent of target revenue on the transmission network, are also consistent with, or lower than, "current national guidelines."[484]

2020. The ERA also considered determinations by the Australian Energy Regulator, as referenced by Western Power, to determine the consistency of the level of revenue-at-risk caps with the Access Code objective.

2021. The Australian Energy Regulator initially adopted a default revenue-at-risk cap of 3.0 per cent for distribution network service providers under the service target performance incentive scheme, although allowed service providers to propose different levels. The Australian Energy Regulator considered this level would provide sufficient incentive for service providers to improve service performance without imposing undue risk and observed that the largest deviation from target service performance at that time was 2.6 per cent.[485]

2022. The Australian Energy Regulator later amended the default revenue-at-risk limit for distribution network service providers to 5.0 per cent, maintaining the allowance for service providers to propose an alternative rate.[486]

2023. The Australian Energy Regulator has, in separate determinations, both increased and decreased the cap on revenue-at-risk under the service target performance incentive schemes.

2024. In its determination for ETSA Utilities in 2010, for example, the Australian Energy Regulator reduced the cap on revenue-at-risk (from 5.0 per cent to 3.0 per cent) due to concerns about the robustness of data and implementation of a statistical method for deriving major event days:

> To guard against the risk that ETSA Utilities might be inappropriately rewarded because poor but not major event days are excluded, the AER considers that the application of a lower powered scheme is reasonable.[487]

2025. In a separate determination, the Australian Energy Regulator rejected a proposal to apply a lower revenue-at-risk threshold (at 3.0 per cent, rather than 5.0 per cent), because it "results in a reduction to the incentive that the scheme provides a [distribution network service provider] to maintain and improve network reliability."[488]

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484 Western Power, Revised AA4 proposal, Response to the ERA's draft decision, 14 June 2018, p. 203, paras. 1193-4.

485 Australian Energy Regulator, Explanatory statement and discussion paper, Proposed Electricity distribution network service providers service target performance incentive scheme, April 2008, p. 23.

486 Australian Energy Regulator, Electricity distribution network service providers Service target performance incentive scheme, November 2009, p. 15.

487 Australian Energy Regulator, South Australian distribution determination 2010–11 to 2014–15, Final decision, May 2010, p. 360.

488 Australian Energy Regulator, Draft decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015, June 2010, p. 643.

2026. The Australian Energy Regulator sought to avoid setting a general precedent, however, stating that it will "make a decision as to the appropriate application of the service target performance incentive scheme in each determination."[489]

2027. In determining whether the revenue-at-risk caps proposed by Western Power for the fourth access arrangement period are consistent with the Code objective, the ERA considered:

- Customers' expressed preferences that they were not willing to pay for an increased level of service reliability, in general.
- Service performance outcomes achieved by Western Power in the AA3 period, when customers had expressed similar preferences for service performance to be maintained at existing levels of reliability.
- The magnitude of the reduction in the value of customer reliability estimates used to determine reward and penalty rates on the distribution network.
- The application of individual penalty caps at the service standard benchmark level of performance, which limits the effectiveness of the cumulative penalty cap.

2028. The ERA considers the following revenue-at-risk caps to be consistent with the Code objective:

- An upper revenue-at-risk (cumulative net reward) cap of 1.0 per cent on the distribution network.
- A lower revenue-at-risk (cumulative net penalty) cap of 2.5 per cent on the distribution network.
- Reward and penalty revenue-at-risk caps of 1.0 per cent on the transmission network.

Allocation of transmission revenue-at-risk

2029. Western Power also proposed to remove the system minutes interrupted service standard benchmark and targets for the AA4 period and allocate the revenue-at-risk on the transmission network to the remaining performance measures, including circuit availability, average outage duration, and loss of supply event frequency (>0.1 and ≤1.0 minutes, and >1.0 minutes), as shown in Table 181, below.

2030. Western Power accepted the draft decision requiring the reinstatement of the system minutes interrupted (radial networks) performance measure, with reservations, but did not include an allocation of revenue-at-risk to this performance measure in its revised proposal.

[489] Australian Energy Regulator, Draft decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015, June 2010, p. 643.

Table 181: Previous and proposed allocation of revenue-at-risk on the transmission network

Performance measure	AA3 allocation	AA4 proposed
System minutes interrupted (radial networks)	10%	(*removed*)
Circuit availability	50%	50%
Loss of supply event frequency (>0.1 and ≤1.0 minutes)	10%	12.5%
Loss of supply event frequency (>1.0 minutes)	10%	12.5%
Average outage duration	20%	25%

2031. Subsequent to the draft decision, the ERA obtained technical advice that supported the removal of the system minutes interrupted performance measure from the service standard adjustment mechanism, but considered the outage information to provide important information and recommended the continued reporting of performance against this measure.[490]

2032. Consequently, the ERA has removed the system minutes interrupted (radial networks) performance measure from the service standard adjustment mechanism, consistent with Western Power's initial proposal.

2033. The initial version of the service target performance incentive scheme for transmission network service providers required service providers to consider the following factors when proposing revenue-at-risk weightings to transmission performance parameters:

- Consistency of the incentives provided by the performance parameter with the reliability requirements of the National Electricity Rules.
- Availability, accuracy and reliability of data for reporting the values of parameters.
- The scope of the service provider to influence its performance as measured by the parameter.
- The extent of any duplication in parameters or sub-parameters.[491]

2034. The Australian Energy Regulator explained that it has accepted weightings that allocated half of the revenue-at-risk to security of supply parameters (circuit availability) and the remaining allocation to reliability (loss of supply event frequency) and operational response parameters (outage duration). The Australian Energy Regulator considered these weightings to be consistent with the services valued by customers and the objectives of the service target performance incentive scheme.[492]

[490] Geoff Brown & Associates, Service Standard Benchmarks Regulatory Framework, 20 August 2018.

[491] Australian Energy Regulator, Final Decision, Electricity transmission network service providers, Service Target Performance Incentive Scheme, August 2007.

[492] Australian Energy Regulator, Issues Paper, Electricity transmission, Service Target Performance Incentive Scheme, October 2011, p. 28.

2035. In its final decision on the fourth version of the service target performance incentive scheme for transmission network service providers, the Australian Energy Regulator implemented standardised parameter weightings, comprising:

- 0.5 per cent of maximum allowed revenue (revenue-at-risk) due to the importance of unplanned outages as a lead indicator of system security and reliability.

- 0.2 per cent of maximum allowed revenue to the average outage duration (operational response) parameter.

- 0.15 per cent of maximum allowed revenue to each of the loss of supply event frequency (reliability) sub-parameters.[493]

2036. The service target performance incentive scheme for transmission network service providers was subsequently amended to include additional sub-parameters, raising the revenue-at-risk for the service component of the scheme to 1.25 per cent.[494]

2037. The service target performance incentive scheme for transmission network service providers also permits the weighting of a particular parameter to be reduced to zero if there is insufficient reliable or accurate data to determine the value of the parameter.[495]

2038. The ERA considers the parameter weightings listed in Table 182 to be reasonable, consistent with the objective of the Access Code, and consistent with national guidelines.

Table 182: Required allocation of revenue-at-risk on the transmission network

Performance measure	AA4 required weighting
Circuit availability	50%
Loss of supply event frequency (>0.1 and ≤1.0 minutes)	15%
Loss of supply event frequency (>1.0 minutes)	15%
Average outage duration	20%

[493] Australian Energy Regulator, Final decision, Electricity transmission network service providers, Service Target Performance Incentive Scheme, December 2012, pp. 39-40.

[494] Australian Energy Regulator, Explanatory statement, Draft electricity transmission network service providers, Service Target Performance Incentive Scheme, version 5, June 2015, p. 10.

[495] Australian Energy Regulator, Final, Electricity transmission network service providers, Service Target Performance Incentive Scheme, August 2007.

Required Amendment 42

Western Power must set revenue-at-risk caps as follows:

- Upper revenue-at-risk (cumulative reward) cap on the distribution network of 1.0 per cent.
- Lower revenue-at-risk (cumulative penalty) cap on the distribution network of 2.5 per cent
- Reward and penalty revenue-at-risk caps of 1.0 per cent on the transmission network.

Required Amendment 43

Western Power must allocate revenue-at-risk to the performance measures on the transmission network at the rates shown in Table 182.

Table 183 Incentive rates proposed by Western Power and required by the ERA for the AA4 period

Performance measure	Unit rate	Proposed reward	Proposed penalty	Required reward	Required penalty
Distribution reliability performance measures					
System average interruption duration index (minutes)					
CBD	minutes	$26,734	$26,734	$30,215	$30,215
Urban	minutes	$366,800	$366,800	$446,660	$446,660
Rural short	minutes	$114,374	$114,374	$143,118	$143,118
Rural long	minutes	$41,958	$41,958	$52,503	$52,503
System average interruption frequency index (interruptions)					
CBD	0.01 events	$30,114	$30,114	$29,711	$25,683
Urban	0.01 events	$366,867	$366,867	$291,763	$285,256
Rural short	0.01 events	$117,788	$117,788	$91,810	$91,567
Rural long	0.01 events	$65,982	$65,982	$55,285	$50,662
Call centre performance (%)	0.1%	-$41,140	-$9,540	-$37,991	-$41,445
Transmission reliability performance measures					
Circuit availability (%)	0.1%	-$434,953	-$193,313	-$441,759	-$252,434
Loss of supply event frequency (interruptions)					
>0.1 and ≤1.0 system mins.	events	$43,495	$54,369	$66,264	$75,730
>1.0 system minutes	events	$108,738	$217,477	$176,704	$265,056
Average outage duration (mins.)	minutes	$1,883	$3,000	$1,571	$5,565

D-factor

2039. The D-factor provides for the recovery, in the next access arrangement period, of operating expenditure incurred as a result of deferring a capital expenditure proposal or for demand-management initiatives.

2040. The Access Code does not include a mechanism for the retrospective recovery of non-capital costs, which could result in Western Power not choosing the overall least cost option. The D-factor scheme was approved to remove this apparent disincentive.

Western Power's initial proposal

2041. Western Power proposed adding new sections 7.6.6 to 7.6.10 to the access arrangement to enable it to lodge an application during the access arrangement period for a determination on whether expenditure satisfies the D-factor non-capital costs test:

> 7.6.6. Western Power may at any time during this access arrangement period apply to the Authority for the Authority to determine that a business case contains proposed non-capital costs that satisfy the D factor non-capital costs test.
>
> 7.6.7 If an application is made to the Authority under section 7.6.6 the Authority must make a determination within 25 Business Days.
>
> 7.6.8 If the Authority determines that proposed non-capital costs satisfy the D factor non-capital costs test ("approved business case amount") then if D factor incurred costs are not more than the approved business case amount the Authority will add the D factor incurred costs to Western Power's target revenue in the next access arrangement period. If the D factor incurred costs are more than the approved business case amount, the Authority will add the D factor incurred costs to Western Power's target revenue in the next access arrangement period and Western Power may seek the further amount to be added to target revenue for the next access arrangement period by demonstrating to the Authority's satisfaction that the further amount of non-capital costs satisfy the requirements of section 6.40 and 6.41 of the Code.
>
> 7.6.9 A determination of an approved business case amount does not oblige Western Power to proceed with the project that is the subject of the business case.
>
> 7.6.10 If the Authority determines that proposed non-capital costs do not satisfy the D factor non-capital costs test then the Authority will provide reasons for that determination to Western Power and Western Power may make an amended application under section 7.6.6.

Submissions on Western Power's initial proposal

2042. ATCO Gas Australia (ATCO) submitted that continuing to provide the D-factor in the access arrangement helped to deal with future uncertainties and the possible effects of new technologies.

2043. Mr Noel Schubert's submission supported Western Power's proposed amendment to enable it to lodge an application during an access arrangement period:

> My many years of experience working in Western Power and its predecessors on alternative (non-network) solutions including demand management, to which the D-factor scheme applies, are that there has often been a 'cultural reluctance' to investigate and implement such solutions. Network solutions have generally been preferred also because of things that make non-network solutions more difficult or less attractive to justify, gain approval for, and implement even when they would be the

most economically efficient solution. Having to seek retrospective approval for D-factor (noncapital) expenditure after the access arrangement period in which the expenditure would be incurred is one such 'barrier' that adds to this reluctance.

In my opinion, from experience, these amendments are necessary to help ensure Western Power chooses the overall least cost option when choosing between capital and non-capital solutions.

2044. Synergy considered the proposed D-factor did not entirely address the bias towards network options over non-network options related to demand management. It considered the D-factor should be reworked to "provide stronger incentives for Western Power to pursue demand management activities, drawing in particular on the proposed DMIA and DMIS in the NEM".

2045. Synergy also considered Western Power's proposal that the ERA make a determination within 25 business days would lead to determinations that have to be hastily made without time for public consultation or gathering full information.

Considerations of the ERA

2046. As set out in the section on adjustments to target revenue for D-factor expenditure during AA3, the ERA considers the D-factor has effectively enabled Western Power to adopt non-network options without exposing customers to higher costs from inaccurate forecasts of network control service costs.

2047. 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.

2048. The ERA noted in the draft decision that the Access Code already includes provisions for Western Power to submit an application for approval of non-operating costs at any time during an access arrangement.[496] The ERA considered there was no need for an additional D-factor non-capital costs test (as proposed by Western Power), and in any case, such a test was not contemplated under the Access Code.

2049. The ERA's draft decision required the following amendment to Western Power's proposal.

Required Amendment 38

Western Power must delete proposed new sections 7.6.6 to 7.6.10 from the access arrangement.

2050. Western Power has not accepted draft decision required amendment 38 and submits the following.[497]

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.

In the AA4 proposal, Western Power submitted amendments to the D-factor, which provided:

[496] Sections 6.76 to 6.80 of the Access Code.

[497] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 209-212.

- 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.

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.

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.*

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.*

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.

A timely, clear and robust process for recovering the cost of any non-capital alternative options will ensure that capex is not unduly preferred.

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.

The D-factor is not intended to provide incentives to pursue demand management activities

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.

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*.

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.

The Access Code includes alternative recovery provisions

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.

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.

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.

The D-factor is not expressly considered in the Access Code

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; …*

We note that in its AA2 Final Decision, the ERA considered that the D-factor scheme *is consistent with the requirements of the Access Code308. 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*. We agree that the D-factor has been successful in helping us balance the capex and opex incentives.

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.

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.

Consistency with the Access Code objective and chapter 5

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.*

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.

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.

Further amendments to allow for consultation

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.

We agree that the timeframe may be too short if the ERA wish to consult on the application.

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.

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.

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.

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.

2051. A submission from ATCO was received on the draft decision:

> ATCO encourages the ERA to consider whether the existing provisions in the Access Code (6.76 – 6.80) adequately provide for the certainty that Western Power are seeking in relation to timeframes and if not, there is another way to provide guidance to Western Power as to the meaning of "within a reasonable time" in section 6.77 of the Access Code. This would help improve cost certainty and minimise the impact on consumers' electricity bills.

2052. As noted in the draft decision, the D-factor is not intended to provide incentives for Western Power to pursue demand management activities. This comment was made in the context of Synergy's submission on Western Power's initial proposal that the D-factor should provide stronger incentives for Western Power to pursue demand management activities similar to the proposed Demand Management Innovation Allowance (DMIA) and Demand Management Incentive Scheme (DMIS) in the National Electricity Market As also expressed in the draft decision, the D-factor provides for the recovery, in the next access arrangement period, of operating expenditure incurred as a result of deferring a capital expenditure proposal or for demand-management initiatives. The Access Code does not include a mechanism for the retrospective recovery of non-capital costs, which could result in Western Power not choosing the overall least cost option. The D-factor scheme was designed to remove this apparent disincentive.

2053. In its revised proposal, Western Power submits that sections 6.76 to 6.80 of the Access Code are not adequate to enable it to lodge an application during the access arrangement period for a determination on whether expenditure satisfies the D-factor non-capital costs. Specifically, it submits these sections do not reference section 6.41 of the Access Code and do not provide for the approved amount to be financially neutral for Western Power.

2054. Contrary to Western Power's view, section 6.41 is included as sections 6.76 to 6.80 of the Access Code refer to section 6.40 which is subject to section 6.41. The adjustments to make the cost financially neutral would be undertaken at the next access arrangement review under the D-factor calculation.

2055. The ERA concurs with Western Power's view that under section 4.29(b) of the Access Code there is discretion to approve a proposed access arrangement containing something not listed in section 5.1. However, as described above, there are already existing provisions in the Access Code; consequently, there is no basis to exercise that discretion.

2056. The ERA maintains draft decision required amendment 38.

Required Amendment 44

Western Power must delete proposed new sections 7.6.6 to 7.6.10 from the access arrangement.

Deferred revenue

2057. The current access arrangement includes provision for a deferral of revenue from the AA2 period with the deferred amount (escalated for inflation and by the rate of return) to be included in target revenue in subsequent access arrangement periods.

Western Power's initial proposal

2058. Western Power updated the values in the access arrangement (sections 7.7.1 to 7.7.3) to reflect the opening balance for the fifth access arrangement period (AA5) at June 2017 prices and the remaining time frame for recovering the deferred revenue.

2059. Western Power calculated the value at the beginning of AA5 as $89.0 million ($ real as at June 2017) for transmission, to be recovered over 40 years and $642.9 million ($ real as at June 2017) for distribution, to be recovered over 32 years.

Submissions on Western Power's initial proposal

2060. No submissions on Western Power's initial proposal addressed this matter.

Considerations of the ERA

2061. In the draft decision, the ERA found that Western Power had updated the values of deferred revenue and remaining lives consistent with the current access arrangement.

2062. No submissions were received on the draft decision. The ERA maintains its draft decision.

TRIGGER EVENTS

Access Code requirements

2063. Under section 5.34 of the *Electricity Networks Access Code 2004* (Access Code), an access arrangement may specify one or more trigger events. A trigger event is defined in the Access Code as a set of one or more circumstances specified in the access arrangement, the occurrence of which requires a service provider to submit proposed revisions to the ERA under section 4.37 of the Access Code.

2064. Trigger events may be either proposed by the service provider or included in an access arrangement by the ERA under section 5.35 of the Access Code.

2065. Under section 5.36 of the Access Code, before determining whether a trigger event is consistent with the Access Code objective, the ERA must consider:

- Whether the advantages of including the trigger event outweigh the disadvantages of doing so, in particular the disadvantages of decreased regulatory certainty.
- Whether the trigger event should be balanced by one or more other trigger events.[498]

Current access arrangement

2066. Trigger events are set out in section 8.1.1 of the current access arrangement and are defined as:

> … any significant unforeseen development which has a materially adverse financial impact on the service provider and which is:
>
> (i) outside the control of Western Power; and
>
> (ii) not something that Western Power, acting in accordance with good electricity industry practice, should have been able to prevent or overcome; and
>
> (iii) so substantial that the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the impact of the variation on regulatory certainty.

2067. Section 8.1.2 of the current access arrangement includes carbon policies, full retail contestability and the mandated roll-out of advanced interval meters as events which may give rise to a trigger event.

2068. Section 8.1.3 of the current access arrangement requires that Western Power must submit proposed revisions to the ERA within 90 business days after a trigger event has occurred.

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[498] The Access Code provides the following example: "The *service provider* may wish to include a *trigger event* allowing it to reopen the *access arrangement* if actual *covered service* consumption is more than x% below forecast. However, if the *ERA* were minded to allow such a *trigger event*, it may also require the inclusion of a complementary *trigger event* requiring the *service provider* to reopen the *access arrangement* if *covered service* consumption is more than y% above forecast."

Western Power's initial proposal

2069. Western Power proposed to amend section 8.1.2 of the access arrangement as follows:

> A *trigger event* may include without limitation the introduction of any scheme or mechanism with respect, directly or indirectly, to emissions of greenhouse gases and with respect to any activity including pricing, reduction, cessation, offset and sequestration, ~~(including the Carbon Pricing Mechanism announced by the Commonwealth in February 2011), full retail~~ contestability, ~~and the mandated roll-out of Advanced Interval Meters,~~and any other government energy reforms, to the extent that such costs were not included in the calculation of *target revenue* for this *access arrangement period* or otherwise addressed through the unforeseen event provisions in sections 7.1.1 to 7.1.4 of this *access arrangement*.

Submissions on Western Power's initial proposal

2070. Emergent Energy submitted that the broad definition included in section 8 of Western Power's access arrangement would not appear to require the specification of particular triggers. However, it considered it would be preferable if energy market reforms were treated as a defined trigger event, rather than being included as a force majeure event, with any costs recovered in subsequent periods:[499]

> In this way, the Authority has the ability to properly assess the impact of reforms to Western Power, and whether these impacts form part of the expected operational and market risks that are expected to be prudently managed by Western Power.

2071. Alinta Energy (Alinta) and ERM Power did not consider government energy reforms should be included as a trigger event.

2072. ERM Power considered government energy reforms were a risk every market participant faces in a changing regulatory environment and each market participant generally bears its own costs. It also considered:[500]

> Western Power is aware and has been aware for some time now of the Government's desire to move to a constrained network access environment. Western Power would have determined as part of its operating cost, the cost of having a regulatory team working on regulatory reforms as part of its business. Therefore, given that Western Power has a team of regulatory specialists already, it is not appropriate for "government energy reforms" to be deemed a trigger event.

2073. Alinta submitted that government energy reforms were too broad and undefined to be included as a trigger event:[501]

> There could be any number of government energy reforms (i.e. a change to the metering code for example) that could in no way be defined as "so substantial that the advantages of making a variation to this access arrangement before the end of this access arrangement period outweigh the disadvantages". The proposal that any government energy reform could reopen an access arrangement for reconsideration gives rise to significant and untenable regulatory uncertainty. Alinta values certainty,

[499] Emergent Energy, *Western Power AA4 Discussion Paper*, 8 December 2017.

[500] ERM Power (NewGen Neerabup Partnership), *Issues Paper on Proposed Revisions to Western Power's Network Access Arrangement*, 11 December 2017, p. 3.

[501] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 12.

> and as such, we advise caution against including such a broad and undefined trigger event.

2074. Alinta also raised concerns about Western Power's proposal to amend the "full retail contestability" trigger event to "contestability":

> Alinta agrees that a move to [full retail contestability] could have a material financial impact on Western Power, specifically in regards to the development of IT systems to facilitate [full retail contestability] (assuming that Western Power retains its role as Retail Market Operator). However, Alinta would question whether a reduction in the contestability threshold would be deemed to be a significant enough event to warrant reopening of the Access Arrangement.

Draft decision

2075. The Access Code includes provisions which enable an access arrangement to be amended prior to the revision date specified in the approved access arrangement as a result of new developments:

- Section 4.37 requires the service provider to notify the ERA if the conditions of a trigger event specified in its access arrangement are satisfied and submit proposed revisions to the ERA by the designated date. The ERA must consider the proposed revisions in accordance with sections 4.46 to 4.52 and sections 4.2 to 4.36, which is the same process it must follow for a standard access arrangement review.
- Section 4.38(b)(ii) permits the ERA to vary the price control or pricing methods by issuing a notice, if it determines that significant unforeseen developments have occurred that are:
  - Outside the control of the service provider.
  - Not something the service provider, acting in accordance with good electricity industry practice, should have been able to prevent or overcome.
  - The effect is so substantial that the ERA considers the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the effect of the variation on regulatory certainty.
- Section 4.41 provides for the ERA to vary the access arrangement by issuing a notice as a consequence of any relevant amendments if there is an Access Code change.
- Section 4.41A provides a broad remit to Western Power to propose mid-period variations and the ERA to approve them by issuing a notice. When evaluating such proposals, the ERA must determine whether the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the effect of the variation on regulatory certainty.

2076. In contrast to the full access arrangement review required under a trigger event, when considering and implementing revisions under sections 4.38, 4.41 or 4.41A, the ERA is not obliged to undertake a complete review of the access arrangement. Its decision is published by a notice and it must follow the requirements of Appendix 7 of the Access Code for any public consultation.

2077. Section 8.1.1 of the current access arrangement was approved for the first access arrangement period (AA1). The ERA determined a service provider should be entitled to revisit an access arrangement if an event beyond its control had a material effect on its ability to provide covered services. Although Western Power also proposed including specific events that it considered would result in material cost increases,[502] the ERA did not approve them as it considered such costs could be dealt with as a cost pass through under section 4.38 of the Access Code.

2078. In its AA1 decision, the ERA also considered whether "materially adverse impact" should be replaced with "material impact" so the mechanism would apply in the same way to events that decrease Western Power's costs as to those that increase costs. However, it decided the events contemplated by this section are generally events that give rise to disruption to the operations and/or assets of the transmission and distribution networks, and that a disruption is more likely to give rise to an increase in costs than a decrease in costs. Accordingly, the ERA took the view that it was not necessary for the trigger event specified to be balanced by a trigger event for events that give rise to cost reductions to Western Power.

2079. The addition of section 8.1.2 was approved for the second access arrangement period (AA2). The ERA accepted that the events specified in section 8.1.2 could fall within the scope of the existing section 8.1.1, but noted they were simply declaratory in effect and therefore, did not constitute a material change from the AA1 access arrangement.

2080. As stated in the draft decision, and consistent with the view the ERA held for AA1, Western Power should be entitled to revisit its complete access arrangement if an event beyond its control has a material effect on its ability to provide covered services.

2081. However, although the events listed in section 8.1.2, including the revisions proposed by Western Power in its initial proposal, could fall within the scope of 8.1.1, it is not necessarily the case that they would have a material effect on its ability to provide covered services. In particular, as identified in stakeholder submissions, "government energy reforms" is a very broad term which could include both small and large reforms.

2082. The concerns raised by Emergent Energy that costs arising from any reforms need to be properly assessed, rather than being claimed as force majeure costs by Western Power at the next review, can be dealt with, if necessary, by the provisions for mid-period revisions under sections 4.38, 4.41 and 4.41A of the Access Code. As noted above, these are less onerous reviews than required for a trigger event as the ERA is not obliged to undertake a complete review of the access arrangement for mid-period revisions.

2083. 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 confusing and should be deleted from the access arrangement.

2084. The ERA's draft decision required the following amendment to Western Power's proposal.

[502] These included a decision by the State Government that imposed costs on Western Power in order to facilitate the development of market rules, or the introduction of contestability, or a government decision by that required Western Power to reorganise or restructure its operations.

Draft Decision Required Amendment 39

Section 8.1.2 of the proposed revised access arrangement must be deleted.

Western Power's revised proposal

2085. In its revised proposal, Western Power has accepted draft decision required amendment 39 and has deleted section 8.1.2 from the access arrangement.

2086. Western Power submits a further change it wishes to make:[503]

> … 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 any impact of a significant unforeseen event where the advantages of the revision outweigh the cost.
>
> 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.
>
> 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 …

Submissions on draft decision

2087. No submissions relevant to trigger events were received.

Considerations of the ERA

2088. The ERA is satisfied Western Power has complied with draft decision required amendment 39.

2089. In its revised proposal, Western Power refers to section 4.38(a) of the Access Code as providing for the ERA to re-open the access arrangement in-period for any significant unforeseen event where the advantages of revision outweigh the cost. Western Power considers this provides the ERA with broader provisions than Western Power has because section 8.1.1 of the access arrangement refers to events which have a materially adverse *financial* impact, whereas Western Power considers section 4.38(a) does not have such a restriction.

2090. Section 4.38 of the Access Code does not apply to trigger events. It applies to the revision of the price control or pricing methods during an access arrangement. It is likely such a revision would only arise as a result of events with a financial effect.

[503] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 213-214.

2091. As set out in paragraph 2075 above, section 4.41A of the Access Code provides a broad remit to Western Power to propose mid-period variations, with no restriction that the event must have a financial effect.

2092. The trigger event specified in Western Power's access arrangement during AA1 and AA2 did not include the word "financial". It is unclear why Western Power amended it for the third access arrangement period (AA3) and it was not put forward as a revision for the ERA to consider during the AA3 review.

2093. Regardless of whether the word "financial" is retained or deleted, Western Power is required to demonstrate the effect is so substantial that the advantages of making the variation before the end of the access arrangement period outweigh the disadvantages, having regard to the impact of the variation on regulatory certainty.

2094. On this basis, the ERA is satisfied that Western Power's proposal to delete "financial" from section 8.1.1 of the access arrangement will still result in the trigger event definition being consistent with the Access Code requirements.

SUPPLEMENTARY MATTERS

Access Code requirements

2095. Section 5.1(k) of the *Electricity Networks Access Code 2004* (Access Code) requires that an access arrangement include provisions dealing with supplementary matters under sections 5.27 and 5.28. These comprise:

- Balancing.
- Line losses.
- Metering.
- Ancillary services.
- Stand-by.
- Trading.
- Settlement.
- Any other matter in respect of which arrangements must exist between a user and a service provider to enable the efficient operation of the covered network and to facilitate access to services, in accordance with the Access Code objective.

2096. Section 5.28 of the Access Code requires that the supplementary matters be dealt with in the access arrangement in accordance with other relevant regulatory requirements including written laws, the Wholesale Electricity Market (WEM) Rules and the Technical Rules.

Current access arrangement

2097. Supplementary matters are dealt with in sections 9.1 to 9.7 of the current access arrangement. The requirements of section 5.28 of the Access Code are met by specifying that the requirements in respect of each matter will be in accordance with the WEM Rules, Electricity Industry Metering Code and/or Metering Code Model Service Level Agreement.

Western Power's initial proposal

2098. Western Power submitted:

> … many of the supplementary matters defined in the Access Code now relate to WEM functions rather than Western Power's activities. Several of Western Power's functions such as balancing and trading have transferred to the AEMO. Western Power's functions such as balancing and trading have transferred to the AEMO. Western Power's role is now more that of a traditional network operator and meter data agent under the WEM Rules.
>
> Western Power therefore proposes revisions to the access arrangement to clarify that it:
>
> - does not have any direct requirements to perform balancing, ancillary services, stand-by, trading or settlement functions, but

- will continue to fulfil its obligations as a network operator and meter data agent under the WEM Rules and Technical Rules to support the AEMO in performing its functions, including by providing network and metering information.[504]

2099. Western Power proposed to:

- Delete the following sections from the access arrangement:
  - 9.1 Balancing
  - 9.4 Ancillary services
  - 9.5 Stand by
  - 9.6 Trading
  - 9.7 Settlement
- Insert a new general section (9.1) stating:

  9.1.1 Previous versions of the access arrangement have referred, in the Supplementary Matters chapter, to balancing requirements, ancillary service, trading and settlement requirements.

  9.1.2 Under the Wholesale Electricity Market Rules these functions are now principally undertaken by the Australian Energy Market Operator (“AEMO”).

  9.1.3 However Western Power will discharge such obligations in relation to these matters as they are imposed upon Western Power by the Wholesale Electricity Market Rules from time to time and, in accordance with those rules, support AEMO in discharge of its functions including by providing information to AEMO as required by the Wholesale Electricity Market Rules. As at 2 October 2017 this access arrangement is prepared by Western Power, the principal role Western Power will have is to provide network information to AEMO to support settlements and balancing.
- Amend section 9.3.1, which deals with metering, as follows:

  9.3.1 Metering requirements under the access arrangement shall be in accordance with the Electricity Industry (Metering Code) ~~2005~~2012 and the model service level agreement most recently approved by the Authority under the Electricity Industry (Metering Code) 2012.~~Metering Code Model Service Level Agreement.~~

Submissions on Western Power’s initial proposal

2100. The Australian Energy Market Operator (AEMO) supported Western Power’s proposed amendments to sections 9.1 to 9.7 of the access arrangement, noting that the amendments reflected the market-related functions previously undertaken by Western Power had been transferred to AEMO, and that Western Power would continue to fulfil its obligations as a Network Operator and Metering Data Agent.[505]

2101. Mr Stephen Davidson considered section 9.4 (ancillary services), should not be removed:

> It is inappropriate to delete this clause, because Western Power should be accountable for any indirect increase of costs of electricity to transmission and distribution

[504] Western Power, *Access arrangement information: Access arrangement revisions for the fourth access arrangement period*, 2 October 2017, p. 272.

[505] AEMO submission p. 5.

consumers it causes, via increasing the aggregate cost of operation of the Wholesale Electricity Market (WEM) under the Wholesale Electricity Market Rules.

2102. Mr Davidson recommended reinstating and amending section 9.4.1 as follows:

9.4.1 Requirements for the treatment of ancillary services under the *access arrangement* shall be in accordance with the Wholesale Electricity Market Rules. Western Power should be accountable for any indirect increase of costs of electricity to transmission and distribution consumers it causes, via increasing the aggregate cost of operation of the Wholesale Electricity Market (WEM) under the Wholesale Electricity Market Rules.

Western Power's obligation includes without limitation any action, inaction or exercise of its discretion granted to Western Power under the Technical Rules the consequences of which result in an increased electricity prices to residential, small business, small commercial and other consumers of electricity that could have been avoided otherwise.

2103. Mr Davidson also recommended amendments to section 9.2.1 to clarify that the obligation is for the whole South West Interconnected Network and Western Power has an obligation to minimise line losses:

9.2.1 For parts of the transmission system covered under the Wholesale Electricity Market Rules, the requirements for the treatment of line losses under the *access arrangement* shall be in accordance with the Wholesale Electricity Market Rules.

It is the obligation of Western Power to minimise line losses on the distribution system and on parts of the transmission system covered under Chapter 5 of the Technical Rules (which is not covered by the Wholesale Electricity Market Rules), in order to minimise the cost of electricity to transmission and distribution users".

Considerations of the ERA

2104. In its draft decision, the ERA determined that it was consistent with sections 5.27 and 5.28 of the Access Code to delete the sections in the access arrangement referring to the supplementary matters of "balancing requirements", "ancillary services" and "trading and settlement requirements".

2105. Western Power adequately dealt with each supplementary matter in the proposed (new) section 9.1 by describing, consistently with the WEM Rules, the extent to which the WEM Rules confer obligations on Western Power in each supplementary matter and how Western Power proposes to discharge those obligations. However, the ERA considered some of the drafting in section 9.1 should be inserted in the form of a note to the section. The ERA's draft decision required Western Power to replace its proposed sections 9.1.1 to 9.1.3 with the following:

9.1.1 Western Power will discharge its obligations for balancing requirements, ancillary services, trading and settlement requirements in accordance with the Wholesale Electricity Market Rules and, in accordance with those rules, support AEMO in discharge of its functions including by providing information to AEMO as required by the Wholesale Electricity Market 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 Wholesale Electricity Market Rules these functions are now principally undertaken by the Australian Energy Market Operator ("AEMO").

As at 2 October 2017 this access arrangement is prepared by Western Power, the principal role Western Power will have is to provide network information to AEMO to support settlements and balancing.}

2106. In its draft decision, the ERA considered Mr Davidson's submission on Western Power's initial proposal to reinstate and amend section 9.4.1 was beyond the scope of supplementary matters. This is because Western Power's obligations are confined to those provided for under the Access Code, WEM Rules, Technical Rules and other statutory instruments. As there is no written law that requires Western Power to be accountable for indirect increases of costs of electricity caused by increasing the aggregate cost of operation of the WEM, Mr Davidson's proposed drafting is inconsistent with section 5.28 of the Access Code.

2107. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 [paragraph 2105 above].

2108. Mr Davidson's submission on the draft decision refers to his submission on Western Power's initial proposal (and discussed in paragraphs 2101 to 2103 above). Mr Davidson still considered that his proposed amendment should be made and submitted the following to support his proposal.[506]

Prudent network operators must liaise and cooperate with the AEMO, because power the laws of the land and physics apply to power systems.

Earlier situations that affected power system and WEM operation arose in respect of managing connection applications. These were addressed by explicitly mandating obligations of Western Power to consult with the AEMO/SM/IMO, for example, see clause 3.3.3.8(b) and clause 3.4.2(c)(1) of the Technical Rules.

Recent FOI request revealed that Western Power has no internal procedures that ensure compliance with own obligations arising from the Technical Rules, nor for exercising own discretion granted to it under the Technical Rules.

For example, mass proliferation of small-scale generation (for example, solar PV) appears to have been apparently uncontrolled. These are individually small, however, in aggregate they behave like the largest single generator in the SWIS. Their inadequate characteristics are adversely affecting SWIS system operation, as evidenced by recent AEMO presentation (Cameron Parrotte).

Western Power has power to request modification of the proposed characteristics of the equipment, even to refuse connection: for example, clause 3.7.1(b) reads "Nothing in this clause 3.7 obliges Network Service Provider to approve the connection …", but do not exercise them. Examples are numerous.

It could be therefore argued that failure to consult with the AEMO is the failure to exercise own discretion, it is unreasonable, hence the liability should be a consequence.

If that failure, over a shorter or longer period of time, adversely affects other users, to the extent that the adversely affects operation of the whole power system, including the AEMO, then that liability should not be capped by completely removing liability for, otherwise, avoidable increased cost of the scheduled generation and increased

[506] Stephen Davidson, *Submission Six on draft decision*, pp. 2-4.

quantity of the ancillary services Western Power cause, as non-prudent network service operator.

The proposed qualifier "indirect increase of costs of electricity … it causes…" limits that liability of Western Power only to the consequences of the 'things firmly under the control of Western Power'.

The proposed qualifier excludes the liability of Western Power for 'things not under the control of Western Power', for example compliant operation of other network users and AEMO exercising own discretion (to put the system safety above the market purity).

2109. As set out in the draft decision, the matters raised in Mr Davidson's submission were beyond the scope of supplementary matters. This is because Western Power's obligations are confined to those provided for under the Access Code, WEM Rules, Technical Rules and other statutory instruments. As there is no law that requires Western Power to be accountable for indirect increases in costs of electricity caused by increasing the aggregate cost of operation of the WEM, Mr Davidson's proposed drafting was inconsistent with the requirements of section 5.28 of the Access Code.

2110. In its revised proposal, Western Power has accepted draft decision required amendment 40 and has made the required changes with some minor drafting modifications.[507]

2111. The ERA is satisfied Western Power has complied with draft decision required amendment 40.

2112. In the draft decision the ERA accepted, in principle, Mr Davidson's submission that section 9.2.1 of the access arrangement should be amended to clarify that Western Power has obligations for line losses under the Technical Rules. For the reasons above, the ERA confined the drafting amendments to requiring compliance with the Technical Rules. The ERA required Western Power to amend section 9.2.1 of the access arrangement as follows:

9.2.1 For parts of the transmission system subject to the Wholesale Electricity Market Rules, the requirements for the treatment of line losses under the access arrangement shall be in accordance with the Wholesale Electricity Market Rules.

For parts of the transmission system subject to the Technical Rules, the requirements for the treatment of line losses under the access arrangement shall be in accordance with the Technical Rules.

2113. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 [paragraph 2112 above.]

2114. In its revised proposal, Western Power has not accepted draft decision required amendment 41. Western Power submitted:[508]

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

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[507] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 215.
[508] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 216.

> 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.
>
> 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.
>
> 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.
>
> 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.

2115. Mr Davidson's submission on the draft decision noted:[509]

> the amended wording of section 9.2.1 proposed by the Authority does not include losses on the distribution system, which appears to be a typo that needs to be corrected.
>
> … "treatment" has no technical meaning, and we always try to minimise the power system losses, so this should also be clarified for clarity of meaning.

2116. Mr Davidson's submission on the draft decision proposed that section 9.2.1 of the access arrangement should be amended to read:

> It is the obligation of Western Power to minimise line losses on the distribution system and on parts of the transmission system covered under Chapter 5 of the Technical Rules (which is not covered by the WAEMR), in order to minimize the cost of electricity to transmission and distribution users.

2117. As noted by Western Power, the treatment of line losses in supplementary matters is the calculation of lost energy between the generation of electricity and the consumption point. Western Power is required to make this calculation and provide it to AEMO for the purposes of settlement of the wholesale energy market. The requirements for this calculation are set out in the WEM Rules and are not referred to in the Technical Rules. The ERA agrees with both Western Power and Mr Davidson that the revised wording for draft decision required amendment 41 would incorrectly exclude distribution line losses.

2118. The matters raised in Mr Davidson's submission about minimising line losses are beyond the scope of supplementary matters. As there is no written law specifically requiring Western Power to minimise line losses, Mr Davidson's proposed drafting is inconsistent with the requirements for supplementary matters set out in section 5.28 of the Access Code.

2119. Taking account of the additional information provided by Western Power and Mr Davidson's submission, the ERA is satisfied there is no need to revise the wording in the current access arrangement and therefore does not require Western Power to comply with draft decision required amendment 41.

509 Mr Stephen Davidson, Submission Five on draft decision, p. 2.

STANDARD ACCESS CONTRACT

Access Code requirements

2120. A standard access contract sets out the terms and conditions under which a user may obtain access to a reference service at the reference tariff. Section 5.1(b) of the *Electricity Networks Access Code 2004* (Access Code) requires that an access arrangement include a standard access contract for each reference service.

2121. The specific requirements for a standard access contract are set out in sections 5.3 to 5.5 of the Access Code.

5.3 A standard access contract must be:

(a) reasonable; and

(b) sufficiently detailed and complete to:

(i) form the basis of a commercially workable access contract; and

(ii) enable a user or applicant to determine the value represented by the reference service at the reference tariff.

5.4 A standard access contract may:

(a) be based in whole or in part upon the model standard access contract, in which case, to the extent that it is based on the model standard access contract, any matter which in the model standard access contract is left to be completed in the access arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model standard access contract; and

(ii) section 5.3;

(iii) the Code objective;

and

(b) be formulated without any reference to the model standard access contract and is not required to reproduce, in whole or in part, the model standard access contract.

5.5 The Authority:

(a) must determine that a standard access contract is consistent with section 5.3 and the Code objective to the extent that it reproduces without material omission or variation the model standard access contract; and

(b) otherwise must have regard to the model standard access contract in determining whether the standard access contract is consistent with section 5.3 and the Code objective.

Current access arrangement

2122. Appendix A of the current access arrangement includes a standard access contract, referred to by Western Power as the Electricity Transfer Access Contract (ETAC). The ETAC applies to all reference services offered under the access arrangement.

Western Power's initial proposal

2123. Western Power proposed to retain a single standard access contract (the ETAC), which outlines the terms and conditions for services, tariffs, invoicing and payment, a customer's provision of financial security, technical compliance and liability.

2124. Various amendments to the ETAC were proposed. Western Power submitted the amendments were "to enhance the integrity and development of the network and better achieve the intent of existing provisions".[510]

2125. The proposed changes were set out in Attachment 12.1[511] to the access arrangement information and in a marked-up version of the ETAC provided with the access arrangement.

2126. Western Power advised that the main amendments aimed to:[512]

- Preserve network integrity by strengthening the provisions that require users to keep within their contracted capacity; and require generators (other than small customers operating small scale generators) to give advance notice to Western Power of material changes to their plant.
- Assist with the implementation of new government policies and/or major network changes by allowing Western Power to nominate new services which will be applicable to small customers (for example, a meter upgrade program).
- Ensure the liability provisions operate as intended and are not circumvented by large commercial users utilising the services, but electing not to be party to contractual arrangements with Western Power.
- Clarify that, where a user provides Western Power with a cash deposit, any excess cash which accrues to Western Power (for example due to interest earned) will be refunded to the user on a monthly basis and within a reasonable time.
- Insert a clearer mechanism (Consumer Price Index (CPI) escalation) for the resetting of liability caps.

Submissions on Western Power's initial proposal

2127. Various submissions[513] addressed the proposed amendments to the ETAC. The matters raised in these submissions are considered below.

Considerations of the ERA

2128. Each of the proposed amendments to the ETAC is considered below in the order in which they appear in the contract. The ERA has also considered whether, in view

[510] Western Power, *Access arrangement information*, 2 October 2017, p. 260, paragraph 1097.

[511] Model ETAC for AA4.

[512] Western Power, *Access arrangement information*, 2 October 2017, p. 261, paragraph 1099.

[513] Submissions from Alinta Energy; Australian Energy Council, Community Electricity; ERM Power (NewGen Neerabup Partnership); Stephen Davidson and Synergy.

of practical experience and submissions, the terms and conditions of the ETAC that remain unchanged are still consistent with the requirements of the Access Code.

Standard access contract

2129. Section 5.3 of the Access Code requires a standard access contract to be reasonable and sufficiently detailed and complete to:

- Form the basis of a commercially workable access contract.
- Enable a user (or applicant) to determine the value represented by the reference service at the reference tariff.

2130. The standard access contract may be based in whole or in part upon the model standard access contract (section 5.4(a) of the Access Code). It may also be formulated without any reference to the model standard access contract (section 5.4(b) of the Access Code).

2131. Community Electricity noted the requirements of the Access Code (summarised above) and submitted that:[514]

- It has had the direct experience of applying for a reference service to effect a minor supply. In this instance Western Power offered the full standard access contract (ETAC), which was the same contract it had signed as a retailer.
- Western Power refuses to allow any negotiation of the ETAC, even where this is unreasonable or a barrier to entry. The contractual complexity of the ETAC is a barrier to entry.
- The arrangements in the wholesale electricity market, whereby the market rules apply to any party that registers as a market participant, may assist with the issue of contractual complexity. Under such arrangements, users are contractually bound without the legal administration of a technical contract, and are aware that the terms of the contract are being applied equally to all users.
- There are different versions ("vintages") of the ETAC in use, which creates competitive advantages and impedes competition through discrimination between users.

2132. Other submissions on Western Power's initial proposal raised concerns about proposed amendments that may not meet the requirements of section 5.3 of the Access Code; that is, the proposed amendments may not form the basis of a commercially workable access contract. The ERA considered the matter of a commercially workable contract as part of its last assessment for the third access arrangement period (AA3). The ERA's final decision stated:[515]

> … it is clear from section 5.3 of the Access Code that the [ERA] must ensure that key issues or material terms are addressed in the ETAC in order to form a commercially workable agreement.
>
> A commercially workable contract is one which is based on "business common-sense and commercial reality" and one which "avoid[s] absurdity or inconsistency" or, consequences which appear to be "capricious, unreasonable, inconvenient or unjust".

[514] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, pp. 11-12.

[515] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 5 September 2012, p. 525, paragraphs 2305-2307.

> Accordingly, the [ERA] may decide to insert, amend or delete a term in the ETAC if it considers that to do so will make the contract consistent with business common-sense and commercial reality or avoid an unreasonable or unjust outcome. In deciding whether the ETAC complies with section 5.3 and the Access Code objective, the [ERA] must also have regard to the model standard access contract pursuant to section 5.5 of the Access Code.

2133. In the draft decision, the ERA considered there was no reason to vary its position as to what forms a commercially workable contract and the actions it may take, or matters that it has regard to, when assessing Western Power's proposal for the fourth access arrangement period (AA4).

2134. Community Electricity cited its practical experience dealing with Western Power. The ERA has a limited role managing access negotiations between Western Power and users. Under the Access Code, the ERA, when notified of an access dispute, may settle the dispute by conciliation or refer the dispute to an arbitrator. It may also refer contractual disputes to an arbitrator. For the standard access contract, the ERA's role is to review the proposed amendments and submissions in light of the Access Code requirements and the Access Code objective. The ERA's role is to ensure the ETAC has practical effect and reflects common business practice within this legal framework. Beyond these statutory requirements, the ERA plays no role managing commercial negotiations between the parties.

2135. The ERA considers Community Electricity's concern with there being different versions of the ETAC in operation, and the competitive advantages and discrimination between users that result, below (at paragraph 2144).

Pre-existing contractual rights

2136. In its submission on Western Power's initial proposal, Synergy raised concerns over the primacy of pre-existing contractual rights and noted certain provisions of the Access Code which provide that an access arrangement must not override prior contractual rights. Synergy submitted that "for the [ERA] to perform its obligation in accordance with the [Access] Code objective, [it] considers the [ERA] must first consider and identify any relevant pre-existing contractual rights".[516]

2137. Synergy submitted that it had contractual rights that it considered it would be prevented from exercising if certain proposed changes to the ETAC were approved by the ERA. Synergy did not provide any details of the contractual rights in question because of confidentiality provisions in place between Synergy and Western Power and Synergy's customers.[517] Synergy also submitted the following:[518]

> - The [ERA] should not limit its enquiries to considering previous approved standard access contracts or reference services because there will be a number of access contracts and non-reference services that deviate from the [ERA's] approved documents and services. Further, it will be important to determine whether in the case of the:

[516] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 12, paragraphs 38-40.

[517] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, pp. 4 and 12, paragraph 40.

[518] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 13, paragraphs 41-45.

- transfer and relocation policy parties have modified various rights and obligations under that document; and
- applications and queuing policy parties have modified various rights and obligations under that document.
- The principle of freedom to contract enshrined in section 2.4A of the Access Code provides that Western Power and a user or applicant may negotiate regarding, and may make and implement, an access contract for access to any service (including a service which differs from a reference service) on any terms (including terms which differ from a standard access contract). This provision is subject to an applications and queuing policy in an access arrangement, and any applicable technical rules.
- Section 2.6 of the Access Code provides nothing in the Access Code or an access arrangement prevails over or modifies the provisions of a contract for services, except for present purposes the applications and queuing policy and the technical rules. But importantly, this provision does not entitle the [ERA] to approve any proposed revisions that would have the effect, if approved, of depriving a person of a Pre-existing Contractual Right.
- In addition, to give effect to clause 4.34 of the Access Code, it is crucial the [ERA] ensures that all reference services approved by the [ERA] can be obtained by a user based on the pre-existing terms and conditions of access. That is, the new reference services must be compatible with Pre-existing Contractual Rights including in access contracts and retail contracts.

2138. Sections 4.34 and 4.35 of the Access Code state:

> 4.34 Subject to section 4.35, the Authority must not approve a proposed access arrangement which would, if approved, have the effect of depriving a person of a contractual right that existed prior to the earlier of the submission deadline for the proposed access arrangement and the date on which the proposed access arrangement was submitted.
>
> 4.35 Section 4.34 does not apply to protect an exclusivity right which arose on or after 30 March 1995.

2139. Given Synergy's confidentiality concerns, Synergy noted in its submission that it would be able to discuss the pre-existing contractual rights matter with the ERA on receipt of a notice issued under section 51 of *Economic Regulation Authority Act 2003*. Following receipt of Synergy's submission, the ERA wrote to Synergy on 19 December 2017 stating that the ERA generally relies on the service provider or other interested parties to provide relevant documentary evidence to support any submission made by that party to the ERA. Accordingly, the ERA requested Synergy to provide more information on the nature of the alleged relevant rights that it submitted would be deprived by the proposed access arrangement. The ERA also sought confirmation from Synergy that it had made all reasonable attempts to provide supporting evidence of the relevant rights including any written requests made to affected counterparties seeking consent to disclose the relevant contracts to the ERA.

2140. Synergy informed the ERA on 30 January 2018 that it had engaged with Western Power for the purposes of obtaining its consent to disclose the material nature of these contractual rights. The ERA was informed by Synergy that Western Power required details of the specific contracts and other information Synergy sought to disclose to the ERA prior to making this information available. Synergy indicated that it was preparing a reply to Western Power's request for more information.

2141. Synergy also explained at a general level that the proposed amendments to the following clauses of the access contract, if accepted, would prevent a party from exercising an existing contractual right:

- 3.1(c) in respect of not exceeding contracted capacity.
- 3.2(b) and 3.2(c) in relation to Western Power making unilateral changes to its services applicable to small customers under the access contract.
- 3.3(b) in relation to complying with the eligibility criteria.
- 13(c) in relation to where the user can materially modify any generating plant connected at a connection point.
- 19.11 in relation to the introduction of an obligation in respect of intermediaries.
- Schedule 5 in relation to the capitalisation of the words "claim" and "works".

2142. In its draft decision, the ERA did not agree with Synergy's construction of section 4.34 of the Access Code which appeared to extend the reach of the section to circumstances "where an existing contractual right is not extinguished or amended directly but via some indirect means whereby the right or the benefit of that right is effectively, or practically, deprived e.g. by being adversely impacted". The ERA considered that while the words "have the effect of depriving" in section 4.34 of the Access Code suggested the section was intended to operate broadly in circumstances where the deprivation may be indirect, the subject matter of the protection in section 4.34 was the divesting of the right, not any adverse impact, for example, by way of loss or diminution of economic opportunity. In this circumstance, the word "deprive" was to be given its ordinary meaning, that is, to "divest, strip or dispossess".

2143. Synergy provided further information on its contractual rights to the ERA on 26 February 2018. After reviewing the additional information, the ERA was still of the opinion that pre-existing contractual rights had not been adversely affected.

2144. Community Electricity raised the fact that there were different versions of access contracts in use, and a further version was proposed as part of AA4. Community Electricity considered this created competitive advantages and impeded competition through discrimination between users. The Access Code process is a negotiate-arbitrate model intended to encourage parties to negotiate their own access contract directly. The process is intended to balance the principles of freedom of contract with the fair and non-discriminatory treatment of users.

2145. The evolution of the ETAC is a product of the access arrangement review process under the Access Code, which involves regular review of the access arrangement and the terms of the contract. Overall, each version of the ETAC should represent a commercially workable access contract at the time that it is approved – but the specifics of each will change depending on the access arrangement proposed by Western Power, submissions received and the approval process under the Access Code, which can include consideration of current industry practice.

2146. In the draft decision, the ERA considered that it would be inconsistent with the freedom of contract principle underlying the negotiate–arbitrate model if only a single version of the ETAC was permitted. A single version would have the effect of overriding any negotiations between the parties. In addition, it would be commercially unworkable if all users' contracts were automatically amended every time a new access arrangement was created.

2147. The AEC and Synergy's submissions on the draft decision include further concerns about pre-existing contractual rights. These concerns are discussed in the Reference and Non-Reference Service chapter, as the concerns are about the eligibility criteria for reference services.

Operative provisions for CPI adjustment (clause 1.3)

2148. Clause 1.3 of the ETAC contains a provision for Consumer Price Index (CPI) adjustment. Under the contract, a reference to an amount that is "CPI-adjusted" means that amount is adjusted using the following formula:

$$N = C\ x\ (1 + \frac{CPIn - CPIc}{CPIc})$$

where:

"N" is the new amount being calculated; and

"C" is the current amount being adjusted; and

"CPI_n" is the CPI applicable at the end of the calendar quarter (quarter $_n$) most recently ended prior to the current adjustment date; and

"CPI_c" is the value of CPI applicable at the previous adjustment date.

2149. Western Power proposed to amend the meaning of CPI_c as follows:

"CPI_c" is the value of CPI applicable ~~at the previous adjustment date~~for the calendar quarter occurring 12 months before the calendar quarter referred to in the definition of CPI_n.

2150. Western Power stated that the current meaning of CPI caused an interpretation issue in the case of the first adjustment because there was no previous adjustment. The proposed change removed any ambiguity in the meaning of the clause and did not make any substantive variation to the parties' rights under the contract.[519]

2151. No submissions made to the ERA addressed this proposed amendment.

2152. Western Power's proposal to amend the meaning of CPI clarified how the CPI adjustment operates in practice, and in particular for the first CPI adjustment. In the draft decision, the ERA considered the proposal was consistent with the requirements of the Access Code.

2153. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

Electricity transfer provisions for services (clause 3)

2154. Clause 3 of the ETAC contains provisions for services that cover:

- The provision and use of services (including eligibility criteria) under the contract and any changes to these services.
- The circumstances where increases or decreases to contracted capacity at an existing connection point can occur.

[519] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 2.

- The circumstances where connection points can be added or deleted.
- Amendments to connection point data.

Provision and use of services (clause 3.1)

2155. Clause 3.1(c) of the ETAC currently requires the user to endeavour, as a reasonable and prudent person, to not exceed its contracted capacity. In its initial proposal, Western Power proposed to amend this clause as follows:

> (c) 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.

2156. Western Power stated that the proposed change was to remove the standard of "endeavour not to exceed", which it believed was a low standard given the consequences of exceeding contracted capacity – exceeding contracted capacity threatens the integrity of the network.[520] Western Power also noted the following:

- The proposed change protects both Western Power and network users. A network user exceeding its contracted capacity may adversely impact other network users and require curtailments.
- Some users do not control the equipment at a connection point and only supply electricity to a person at the connection point. In this case the user should discharge its obligation through its contract with the person to require the person to keep within the contracted capacity.

2157. Alinta Energy's (Alinta) submission on Western Power's initial proposal did not agree with the proposed change to clause 3.1(c) to strengthen the provisions requiring users to keep within their contracted capacity (from a reasonable endeavour to an absolute obligation). Alinta considered the change did not meet the reasonableness test to form the basis of a commercially workable contract. Noting that the Excess Networks Usage Charges (ENUCs) framework provides incentives for a generation facility to keep within its contracted capacity, Alinta submitted the following:[521]

> [T]here are scenarios where a user should be able to exceed their contracted capacity. For example, under system abnormal conditions System Management should be able to, and has requested in the past, a generation facility to generate higher than its contracted capacity in order to assist with maintaining power system frequency and security. Alinta notes that Western Power's current ENUCs document allows a generation facility to operate above its contracted capacity twice a year (without incurring ENUCs) for the purposes of Reserve Capacity Testing, this arrangement should continue.

2158. The Australian Energy Council's (AEC) submission on Western Power's initial proposal raised concerns over Western Power's proposal "to impose a strict obligation on retailers to ensure contracted capacity for a connection point is not exceeded". The AEC submitted the proposal must be assessed to be consistent with the Access Code. It noted that the regulatory framework required the ETAC to

[520] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 3.

[521] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 8.1.

be reasonable, sufficiently detailed and complete to form the basis of a commercially workable contract.[522]

2159. ERM Power submitted that the proposed changes to clause 3.1(c) were not workable, especially for generators. It considered the ENUCs provided sufficient incentive for generators to not exceed their contracted capacity at a connection point. It provided the following information in support of its position:[523]

> Currently generators have capacity contracted at the connection point which it knows if it exceeds it has to pay excess network usage charges (ENUC) but if it has to under a dispatch instruction, it will do so as the system operator must have deemed it to be safe. Generators generally endeavour to not exceed its contracted capacity as it is subject to the penalty of paying the ENUC and will not exceed contracted capacity unless it is required to do so, and in most instances this is to provide support to the system. In these instances it is usually to return the grid to a stable, safe and secure operating state after an incident on the system. In such circumstances, the system operator may require these generators to export its maximum capacity, which depending on weather conditions may exceed its contracted capacity at the connection point. The system operator would have deemed it safe for the generator to exceed its capacity at the connection point; otherwise it would have instructed a generator to return to a level where it does not pose a risk to the system.
>
> The proposed change would disrupt this mode of operation and may limit the system operator's ability to return a stressed system to system normal condition in a timely manner. The proposed change is counterproductive as Western Power who may be the counterparty to the ETAC and which wants the grid to be maintained in a stable operating state could actually be contributing to putting the grid at risk under abnormal conditions.
>
> Further to the above, the threat of ENUC charges is sufficient incentive for generators to not exceed their contracted capacity at the connection point.
>
> Clause 3.1(c) should not be modified as it does not contribute to strengthening and ensuring the safe and reliable operation of the grid but could in fact do the opposite. The magnitude of ENUC charges is currently working to ensure generators do not exceed its contracted capacity under system normal conditions but it still allows generators to provide assistance to the grid when it has to.

2160. Synergy's considered Western Power's proposed amendments to clause 3.1(c) were unreasonable for the following reasons:[524]

- The proposed amendments would require retailers to develop comprehensive technical, telemetry and internal monitoring, compliance and enforcement processes to ensure the ongoing compliance of customers. Such processes would be cost prohibitive; and for smaller users (that function as retailers) it may operate as a barrier to entry.
- The proposed amendments sought to externalise existing risk to users and applicants.

[522] Australian Energy Council, Submission on proposed revisions to Western Power's network access arrangement, 11 December 2017, pp. 1-2.

[523] ERM Power (NewGen Neerabup Partnership), *Submission: Issues Paper on Proposed Revisions to Western Power Network Access Arrangement*, 11 December 2017, p. 4.

[524] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 9, paragraphs 23-25.

- Western Power did not demonstrate any instances during the AA3 period where there have been difficulties with users not meeting the current obligation of clause 3.1(c).

2161. Synergy considered the ERA should not approve Western Power's proposed amendments to clause 3.1(c), having regard to section 5.5(b) of the Access Code and the model standard access contract, because the proposed amendments:[525]

- Depart from the standard adopted in the Access Code.
- Externalise risk to users and users' customers that Western Power is better able to manage.
- Impose an onerous performance standard for which there is no clear technical or operational basis.
- Are likely to impact on small retailers entering the retail electricity market via the Western Power Network.

2162. Synergy further considered that Western Power's proposed amendments exceeded its legitimate business interests, contrary to section 26(1)(d) of the *Economic Regulation Authority Act 2003*, and would not, if approved, promote competitive and fair market conduct as contemplated by section 26(1)(e) of the Act.

2163. In the draft decision, the ERA considered Western Power's proposed amendment to clause 3.1(c) of the ETAC and the submissions received, and was of the view the amendment is inconsistent with the requirements of the Access Code. Western Power did not demonstrate by specific examples or data how the current clause has been ineffective, leading to undesirable outcomes for customers or threatening the integrity of the network. Further, Western Power's proposed amendment could have led to unreasonable outcomes, for example, where a generator exceeded contracted capacity as a result of a dispatch instruction from System Management. The existing requirement for a user to *"endeavour, as a reasonable and prudent person"* incorporates a concept of good electricity industry practice. Together with the existing ENUCs, the incorporation of this standard appeared to provide a reasonable mechanism to encourage compliance with contracted capacity limits, which appropriately balances the interests of Western Power and users.

2164. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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."

2165. In its revised proposal, Western Power has not accepted draft decision amendment 42. Western Power submitted:[526]

> 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

[525] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 10, paragraph 26.

[526] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 217-219.

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.

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.

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.'

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.

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.

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.

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.

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.

2166. Western Power proposed the following amendments to clause 3.1 of the ETAC in response to the draft decision.

3.1 Provision and use of Services

…

(c) For each Service at each Connection Point which falls within a category referred to in clause 3.1(e), 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.

(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.

2167. Apart from Western Power's response, there were no submissions on the ERA's draft decision.

2168. Western Power's proposed revisions to the wording of clause 3.1 of the ETAC seek to address the concerns expressed in earlier submissions. However, Western Power still has not demonstrated by specific examples or data how the current clause has been ineffective, led to undesirable outcomes for customers or threatened the integrity of the network. Western Power's revised drafting is inconsistent with the requirements of the Access Code. There is no evidence to demonstrate that the "endeavour, as a reasonable and prudent person" standard and the existing ENUCs have not been effective in encouraging compliance with contracted capacity limits and balancing the interests of Western Power and users.

2169. As stated in the draft decision, the existing requirement for a user to *"endeavour, as a reasonable and prudent person"* incorporates a concept of good electricity industry practice. Together with the existing ENUCs, the incorporation of this standard provides a reasonable mechanism to encourage compliance with contracted capacity limits, which appropriately balances the interests of Western Power and users.

2170. The ERA's final decision, having had regard to the Model Standard Access Contract clause A3.14 and the previously approved ETACs, is that the proposed changes are not consistent with section 5.3 of the Access Code and the Code Objective. The ERA requires the following amendment to Western Power's proposal.

Required Amendment 45

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 proposed clauses 3.1(d) to (g) must be deleted.

2171. In its initial proposal, Western Power proposed to add a new clause 3.1(d) (now clause 3.1(h) in Western Power's revised proposal) to clarify the recipient of services as follows:

> (d) 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.

2172. Western Power submitted that it had two contractual counterparties under the contract – the *user* and the *indemnifier*. The indemnifier's sole contractual role is to provide credit support for the user. The proposed new clause aimed to make clear that services are only provided to the user and the indemnifier had no rights to claim against Western Power – the liability relationship under the ETAC is between Western Power and the user.

2173. No submissions made to the ERA raised concerns with the proposed new clause. The ERA considered the proposed new clause does as Western Power intended– it clarifies that services under the ETAC are provided to the user and not the indemnifier – and is consistent with the requirements of the Access Code.

2174. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. The ERA maintains its draft decision.

User may select services (clause 3.2)

2175. Clause 3.2 of the ETAC sets out provisions for the user to make changes to its services under its contract. Western Power proposed to insert two new clauses as follows:

> 3.2 User may select Services
>
> (a) The User may from time to time give notice to Western Power seeking to change the Service in respect of a Connection Point in accordance with the Applications and Queuing Policy.
>
> (b) If Western Power receives a notice from the User under clause 3.2(a), then Western Power must process that request in accordance with the Applications and Queuing Policy.

(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.

2176. To support the proposed new clauses above, the term “small customer” was added to the dictionary (at schedule 1 of the ETAC) to mean:

> a customer (as defined in the *Electricity Industry Act 2004*) consuming not more than 160 MWh of electricity per annum.

2177. Western Power stated:[527]

> The ETAC does not allow Western Power to initiate a change in the service a customer receives, even if conditions change. Western Power accepts that [this] is appropriate for large customers and changes with them should be negotiated. However for the volume [small] customer market it may be necessary for Western Power to initiate changes to reflect new types of equipment or changes in government policy.
>
> Without [the] ability to vary small customer services Western Power cannot vary services to adapt to the changing configuration and characteristics of the network. This right is becoming more critical in an era of rapid technological change.

2178. A formatting (numbering) error was identified in the ETAC provided at appendix A to the proposed revised access arrangement. Proposed new clause 3.2(c) forms part of existing clause 3.2(b); and proposed new clause 3.2(d) shows as clause 3.2(c). The ETAC was to be amended to fix this formatting error to show new clauses 3.2(c) and 3.2(d) (as set out in paragraph 2175 above).

2179. The ERA’s draft decision required the following amendment to Western Power’s proposal.

> **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).

2180. In its revised proposal, Western Power has accepted draft decision required amendment 43 and has made the required formatting adjustments.[528]

2181. No submissions were received on the draft decision.

2182. The ERA is satisfied that Western Power has complied with draft decision amendment 43.

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[527] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 4.

[528] Western Power, *Revised AA4 proposal: Response to the ERA’s draft decision*, 14 June 2018, p. 219.

2183. Alinta did not consider that the proposed new clause 3.2(c), which gives Western Power a unilateral right to select the reference service (or non-reference service) for a customer, met the reasonable test to form the basis of a commercially workable contract. Alinta considered the customer was best placed to select the retail tariff it wanted, with the retailer selecting the appropriate network/transport tariff.[529]

2184. The AEC raised concerns over Western Power's proposal "to give itself the right (and not the retailer) to determine the transport service a retailer's customer must receive". The AEC submitted the proposal must be assessed to be consistent with the Access Code. It noted that the regulatory framework required the ETAC to be reasonable, sufficiently detailed and complete to form the basis of a commercially workable contract.[530]

2185. Synergy considered the proposed new clauses would:[531]

> Give Western Power an extremely broad right to change the service applicable to the connection point for small customers without the agreement or consent of a user where Western Power:
>
> - modifies or replaces the equipment at or in proximity to the connection point and as a result of that modification or replacement, Western Power considers the service should be changed; or
> - 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).

2186. The new clauses would also have the following consequences:[532]

> Western Power's right to unilaterally vary Services as drafted in clauses 3.2(b) and 3.2(c) *[sic]* means Western Power could substitute an existing Service provided to a User's Small Customer under the [ETAC] with a Reference Service or a Non-reference Service, even if that Non-reference Service is developed without the agreement, prior negotiation or engagement with either of the User or those Small Customers. This is because Service is defined with reference to Exit Service and Entry Service and each of these definitions incorporate the defined term Covered Service which can be a Reference Service or a Non- reference Service. Such a unilaterally developed Non-reference Service would obviously be subject to price, service standard and eligibility criteria that may not have been the subject of agreement between WP and the User.
>
> If a User attempted to revert the Small Customer to the previous Service, WP could simply rely on these clauses to again transfer the Small Customer to a different Service.

2187. Synergy submitted that the (above) approach was unworkable from a contract management point of view. It was also inconsistent with various provisions of the Access Code, including:[533]

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529 Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 8.2.

530 Australian Energy Council, Submission on proposed revisions to Western Power's network access arrangement, 11 December 2017, pp. 1-2.

531 Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 10, paragraph 29.

532 Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, pp. 10-11, paragraph 31.

533 Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 11, paragraph 32.

- Section 5.3, which requires a standard access contract to be reasonable and form the basis of a commercially workable contract.
- Appendix 3, which sets out the model standard access contract.
- Section 2.7, which requires Western Power to use reasonable endeavours to accommodate an applicant's requirements to obtain covered services.

2188. Synergy also considered that Western Power's proposed new clauses, if approved, would constitute a breach of section 115 (prohibitions on hindering or preventing access) of the *Electricity Industry Act 2004*. The proposed new clauses were also inconsistent with the matters that the ERA is required to have regard to under section 26(1) of the *Economic Regulation Authority Act 2003*:[534]

> Western Power's proposed [new] clauses:
>
> - exceed Western Power's legitimate business interests and as such is inconsistent with the matter at section 26(1)(d) of the ERA Act;
> - will not promote regulatory outcomes that are in the public interest and as such is inconsistent with the matter at section 26(1)(a) of the ERA Act;
> - [are not in the long-term interests of consumers]. Network charges comprise approximately 45% of a residential customer's bill. It is not in the long-term interests of consumers to enable a monopoly service provider to unilaterally determine a customer's network Service and price without any independent oversight and as such is inconsistent with the matter at section 26(1)(b) of the ERA Act;
> - will not encourage investment in relevant markets compared to the existing regulatory model whereby Users select the Service on behalf of their customers subject to meeting the Service Eligibility Criteria determined by Western Power and as such is inconsistent with the matter at section 26(1)(c) of the ERA Act;
> - [are] counter to the legitimate business interests of Users relative to the current regulatory arrangement whereby the User selects the Reference Service based on the customer's needs. The current model permits a network user to optimise its customers' network costs; on the other hand, Western Power's proposal will optimise its transport revenue without any external review and as such is inconsistent with the matter at section 26(1)(d) of the ERA Act;
> - will substantially increase Western Power's monopoly market power and limit competitive market conduct as a result of the absence of User network Service choice and as such is inconsistent with the matter at section 26(1)(f) of the ERA Act; and
> - will not promote transparent decision-making processes that involve public consultation as Western Power has no obligation to notify Small Customers of a change in network Service either before or after the change and as such is inconsistent with the matter at section 26(1)(g) of the ERA Act.

2189. Synergy also raised the matter of pre-existing contractual rights, which was considered by the ERA at paragraph 2136 above.

2190. Both Alinta and Synergy considered that Western Power's proposed new clauses 3.2(c) and 3.2(d) failed to meet the requirement of the Access Code to be reasonable and form the basis of a commercially workable contract. The ERA considered the matter of a commercially workable contract in general at paragraph 2132 above. As

[534] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, pp. 11-12, paragraphs 33-37.

indicated, the ERA may decide to insert, amend or delete a term in the ETAC if it considers that to do so will make the contract consistent with business common-sense and commercial reality or avoid an unreasonable or unjust outcome.

2191. The ERA considered the proposed new clauses (3.2(c) and (d)) did not meet the reasonableness test in clause 5.3(a) of the Access Code. The user/retailer should be aware, prior to entering into the standard access contract with Western Power, which services (reference and non-reference services) will be provided to its customers and under what circumstances these services can be unilaterally changed. The proposed amendments may have the effect of depriving the user/retailer, and in turn its customers, of the ability to consent to the new service which may include modified price and eligibility criteria.

2192. With respect to Synergy's other concerns, the ERA gave consideration to the matters listed in section 26(1) of the *Economic Regulation Authority Act 2003.* The ERA agreed that the proposed amendments confer on Western Power a broad power to unilaterally vary the services, which is inconsistent with the requirement to promote competitive and fair market conduct (section 26(1)(e)) and the need to promote transparent decision-making processes (section 26(1)(g)). This is because transparency and fair market conduct requires the user/retailer and in turn its customers to clearly understand the circumstances in which their services may be changed.

2193. Concerning section 26(1)(b), it is possible that a change made by Western Power to a service under the standard access contract with the user/retailer may have flow on effects to the user's customers which may be in the customer's long term best interests, as well as Western Power's legitimate business interests (section 26(1)(d)). This would be the case if in the long term the new services are more cost efficient. It was not clear how the proposed change would affect investment (section 26(1)(c)). Without knowing all of the circumstances when the service under the standard access contract will be unilaterally changed, the likelihood of these effects could not be accurately predicted.

2194. In the circumstances, the ERA considered the proposed amendments conferred on Western Power an unreasonably broad discretion to unilaterally change the services provided under the user/retailer's access contract with Western Power. For this reason, the ERA was of the view that the proposed amendments were inconsistent with the requirements of the Access Code. If Western Power had legitimate concerns which require a change to the services, it was to specify in detail in what circumstances the service will be unilaterally changed.

2195. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision Required Amendment 44

Proposed new clauses 3.2(c) and 3.2(d) must be deleted from the electricity transfer access contract.

2196. In its revised proposal, Western Power has accepted draft decision required amendment 44 and has deleted proposed new clauses 3.2(c) and 3.2(d).[535]

2197. No submissions were received on the draft decision.

[535] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, pp. 219-220.

2198. The ERA is satisfied that Western Power has complied with draft decision required amendment 44.

Eligibility criteria (clause 3.3)

2199. Clause 3.3 of the ETAC details provisions for eligibility criteria. Western Power proposed to delete clause 3.3(b) from the contract as follows:

> 3.3 Eligibility Criteria
>
> ~~(a)~~ 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) Where the User has sought to change the Reference Service in respect of a Connection Point under clause 3.2(a), its obligation under clause 3.3(a) in relation to that Connection Point is subject to compliance by Western Power with clause 3.2(b).~~

2200. Western Power submitted that existing clause 3.3(b) means that where a user has sought to change its reference service, then its obligation to comply with the eligibility criteria is subject to Western Power complying with the applications and queuing policy. Western Power stated that this is incorrect – the user must comply with the eligibility criteria at all times to preserve network integrity, even if Western Power is in breach of the applications and queuing policy.[536]

2201. Western Power considered its proposal to delete clause 3.3(b) removed a potentially adverse provision from the ETAC and did not adversely impact a user's rights against Western Power. Where Western Power failed to comply with the applications and queuing policy the user could take action against Western Power under clause 3.2(b)[537] of the ETAC for breach of contract.

2202. Synergy stated that the removal of clause 3.3(b) from the ETAC would mean that a user may be in breach of its obligation to comply with relevant eligibility criteria even when the breach arises as a result of Western Power's breach of the applications and queuing policy. The removal of the clause had also not been substantiated – Western Power did not provide any commercial, policy or operational evidence why the deletion was necessary to protect its legitimate commercial interests or the safety and security of the network. It had also not demonstrated whether the existing clause had adversely affected it, users or consumers. Additionally, the removal of the clause would require a user to make a legal claim against Western Power to address the breach should Western Power take action or seek to recover under an indemnity under the ETAC – this would increase the likelihood of expensive and time consuming legal proceedings. [538]

2203. The ERA considered Synergy's concerns over the deletion of clause 3.3(b) of the ETAC and agreed clause 3.3 was to be amended to ensure that a user would not be in breach of its obligation to comply with the relevant eligibility criteria in the event that the user's breach arises as a result of Western Power's breach of the applications and queuing policy. Western Power's concerns that the user must comply at all times with the eligibility criteria to preserve network integrity are noted.

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[536] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 5.

[537] Clause 3.2(b) states that: "*If Western Power receives a notice from the User under clause 3.2(a), then Western Power must process that request in accordance with the Applications and Queuing Policy.*"

[538] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, pp. 13-14, paragraphs 48-51.

However, this concern could be addressed whilst still ensuring that the user is not penalised for non-compliance which is caused by Western Power's actions. The ERA recommended the following amended clause 3.3(b), which it considered to be consistent with clause 5.3(a) of the Access Code (i.e. it is reasonable):

> 3.3 Eligibility Criteria
>
> (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).

2204. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 45**
>
> Clause 3.3 of the electricity transfer access contract should be amended in accordance with paragraph 1337 of this draft decision as set out in paragraph 2203 above to ensure that a user will not be in breach of its obligation in the event its breach arises because of Western Power.

2205. In its revised proposal, Western Power has accepted draft decision required amendment 45 with modification. Western Power submits:[539]

> 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'.
>
> 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).

2206. Western Power's proposed modification to clause 3.3(b) is as follows:

> 3.3 Eligibility Criteria
>
> (a) Subject to clause 3.3(b), t~~T~~he 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) 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).

2207. No submissions were received on the draft decision.

2208. Western Power's proposed amendment to insert the words "to the extent that" into clause 3.3(b) captures both a complete inability to comply with the criteria if there is a breach by Western Power, and (what Western Power considers to be the more likely outcome) a partial non-compliance with the eligibility criteria.

[539] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, .p. 220.

2209. Accordingly, the ERA is satisfied that Western Power's proposed modification to clause 3.3(b) meets the requirements of draft decision required amendment 45.

Electricity transfer provisions for controllers (clause 6)

2210. Clause 6 of the ETAC contains provisions for controllers.[540] Clause 6.2 applies in instances where the user is not the controller. Western Power proposed several amendments to clause 6.2(b), which covers indirect damage, as follows:

> 6.2 Where the user is not the controller
>
> …
>
> (b) If the User is not the Controller of a Connection Point, and the Controller of that Connection Point has not entered into a Connection Contract with Western Power in respect of the Connection Point, then the User must ensure that it enters into a Contract with the Controller obliging the Controller to comply with the obligations set out in this Contract (to the extent set out in clause 6.2(a)) and that such ~~any c~~Contract entered into between the User and a Controller relating to Services under this Contract contains a provision:
>
> (i) that neither the User nor Western Power is in any circumstances liable for Indirect Damage suffered by the Controller, however arising, excluding any damage caused by, consequent upon or arising out of fraud; and
>
> (ii) under which the Controller covenants in favour of Western Power (which covenant is expressed to be enforceable by Western Power in accordance with section 11 of the Property Law Act 1969) that it will not bring a claim against Western Power for such Indirect Damage and will not bring a claim which will result in Western Power's aggregate liability to the Controller and the User, under or in connection with this Contract or the Services provided under or in connection with this Contract, exceeding the monetary cap on Western Power's liability in clause 19.5(a).
>
> The exclusion of Indirect Damage in clause 19.3 does not apply to a failure by the User to ensure that its Contract with the Controller contains the covenant referred to in paragraph (ii) above.

2211. Western Power submitted that its proposed amendments mitigated the risk for Western Power that a controller can circumvent the limits on Western Power's liability in the ETAC.[541] The proposed amendments:

- Require the user to have a contract with the controller. Western Power considered this requirement should not be an issue for the user because there should be a documented agreement (contract) if the controller has agreed to control the user's facilities.
- Would allow the controller to give a direct covenant in favour of Western Power in its contract with the user. Western Power would then, as a third party beneficiary, be able to enforce the covenant using section 11 of the *Property Law Act 1969*.

[540] As defined in schedule 1 to the ETAC, a *controller* means *"in respect of a Connection Points, a person, including a Customer, who owns, operates, controls or otherwise is responsible for the operation of the Facilities and Equipment at the Connection Point, and includes the Controller's Workers and Visitors."*

[541] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, pp. 6-7.

2212. No submissions raised any concerns with the proposed changes to clause 6.2 of the ETAC.

2213. The ERA considered the proposed changes were reasonable and consistent with the requirements of the Access Code, subject to a further amendment to the confidentially provisions in the contract.

2214. Western Power's proposed amendments to clause 6.2(b) introduced a requirement for the user to ensure that it enters into a contract with the controller to oblige the controller to comply with the obligations to the extent set out in clause 6.2(a). The ERA considered a user may need to disclose relevant terms of the contract to the controller, so that the controller can agree to the obligations placed upon it. The confidentiality provisions of the ETAC (at clause 33.4) were to expressly permit this 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 …

2215. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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 as set out in paragraph 2214 above.

2216. In its revised proposal, Western Power has accepted draft decision required amendment 46 and has made the required amendments to clause 33.4.[542]

2217. No submissions were received on the draft decision.

2218. The ERA is satisfied that Western Power has complied with draft decision required amendment 46.

Electricity transfer provisions for security for charges (clause 9)

2219. Clause 9 of the ETAC contains provisions that cover security for charges. The existing provisions of clause 9(i) provide that the interest accrued on a cash deposit is only remitted to the user when the security is returned. Western Power proposed to amend this clause to remit interest on a monthly basis, which would benefit users who provide security in the form a cash deposit.[543]

2220. The proposed amendments to clause 9(i) included:

- Amendments to the existing clause to split the clause into *three* separate clauses – clauses 9(i),(j) and (k) – and to include new drafting that requires interest earned on a cash deposit to be remitted to the user on a *monthly basis*,

[542] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 221.

[543] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 7.

if Western Power holds (once interest net of fees and taxes is determined) on behalf of the user cash *in excess of the charges for two months*.

- A new clause 9(j) with updated drafting to require Western Power to return the *whole* security *held as a cash deposit* within a *reasonable time* (where required).
- A new clause 9(k) with updated drafting to make clear that there was no imposing obligation on Western Power to maximise or obtain any return on *cash deposit* amounts that are *held by Western Power as security*.

2221. The amendments were set out as follows:

9. Security for charges

…

(i) Where security is provided to Western Power in the form of a cash deposit, then Western Power shall deposit the amount in an interest bearing account maintained with a financial institution, selected consistently with Western Power's policies, or with the Western Australian Treasury Corporation or other government body. Any interest which accrues on the cash deposit shall form part of the security however where, as at the end of a month, 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' services Western Power will, within a reasonable time, pay the excess amount held (above the Charges for two months' Services) to the Customer's nominated bank account. ~~but~~

(j) Where Western Power is required, under this Contract, to return the whole of a security held as a cash deposit then it will, within a reasonable time, return to the User the unutilised balance of the cash deposit and interest accrued less any charges (including fees and charges associated with maintaining the interest bearing account) and ~~T~~taxes attributable to the maintenance of the interest bearing account.

(k) Nothing in this Contract is to be taken as imposing any obligation on Western Power to maximise or obtain any return on cash deposit amounts held by Western Power as security ~~deposited~~.

2222. No submissions made to the ERA raised any concerns with the proposed changes to clause 9 of the ETAC.

2223. The ERA agreed with Western Power's submission that the proposed changes would benefit users who provide security in the form of a cash deposit, and are consistent with the requirements of the Access Code.

2224. A consequential change to clause 9(f) was required to reflect the amendments to clause 9(j) that cash deposits will be returned to the user within a reasonable time. Western Power's proposed deletion of the word "expiry" in clause 9(f), and the use of the word "taxes" instead of "Taxes" in clause 9(f) and (j), were discussed respectively at paragraphs 2343 and 2370 (below). Similarly, the reference to the word "services" in clause 9(i) was to be capitalised in all instances – this was discussed further at paragraph 2371 (below).

2225. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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…"

2226. In its revised proposal, Western Power has accepted draft decision required amendment 47 and has made the required amendment to clause 9(i).[544]

2227. No submissions were received on the draft decision.

2228. The ERA is satisfied that Western Power has complied with draft decision required amendment 47.

Technical compliance provisions for technical characteristics of facilities and equipment (clause 13)

2229. Clause 13(c) of the ETAC sets out the circumstances where the user can materially modify any generating plant connected at a connection point. Western Power proposed to amend this clause to oblige the user to notify it of a proposed material modification and to only make the modification if it will not adversely impact the safety and security of the network. The proposed amendments were 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:

(i)(A) the User makes such an Application ~~to do so under the Applications and Queuing Policy~~; and

~~(ii)~~(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 days prior to the modifications being made; and

(B) the modified Generating Plant does not adversely impact the safety or security of the Network.

2230. Western Power submitted that the proposed amendments would protect the integrity of the network by ensuring changes to generating plant were only made where there were no adverse impacts on network integrity. The obligation for the user to notify Western Power of a modification to its generating plant would give Western Power

[544] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, .p. 221.

the opportunity to raise any concerns it may have with the user before the modification is made.[545] Western Power also stated that the proposed amendments aimed to exclude generating plant owned by small customers because it was considered impracticable for a user with small customers to give notice each time a small generator was changed.

2231. Alinta questioned whether the proposed changes to clause 13(c) were necessary. It considered the requirement for generators (other than small customers operating small scale generators) to give advance notice to Western Power of material changes to their plant was already adequately provided for under the technical rules, and applications and queuing policy processes.[546]

2232. Synergy considered the proposed amendments were unreasonable and therefore not consistent with section 5.3(a) of the Access Code. The proposed amendments "compound the complexity of how the applications and queuing policy applies" and therefore also fails to form the basis of a commercially workable access contract (as required by section 5.3(b) of the Access Code). Western Power's proposed amendments also do not satisfy the matters that the ERA needs to have regard to under section 26(1) of the *Economic Regulation Authority Act 2003*.[547]

2233. Synergy noted while Western Power has addressed a number of matters it previously raised, Synergy still had the following concerns:[548]

- The proposed new clause does not specify what "materially modify" means and this compounds current uncertainty about the proper application of the AQP. Synergy suggests the access arrangement review process is an opportune time to provide clarity on this term particularly given the existing residential photovoltaic system (PVs) uptake and the future electric vehicle and battery uptake.

- Western Power has not provided a reason as to why it requires written notice at least 60 days prior to the anticipated modification. Synergy previously advised Western Power that such a notification period will impact Synergy's customers and the small-scale renewable energy industry in the SWIS. Synergy recommends the notification period is shortened.

- Further, the requirement the modified Generating Plant does not "adversely impact" the safety or security of the Network effectively imposes a continuing and strict obligation on the User, the parameters of which are not entirely clear. In particular, there is no settled legal meaning of the phrase "adversely impact" but it is clearly intended to have a broad meaning.

- Synergy's concern is the proposed addition of clause 13(c)(ii) does not restrict the continuing obligation to ensuring a Generating Plant's design or installation is undertaken consistent with Good Electricity Industry Practice; however, the proposed new clause goes to the unreasonable lengths of imposing a continuing obligation on the User to ensure the modified Generating Plant does not adversely impact the safety or security of the Network. This is not an obligation that Users presently have under existing ETACs, so the practical effect of this proposed provision will be that Western Power allocates risk it currently carries to Users with each material modification of Generating Plant, even where such modification does not require processing under the AQP. Synergy contends Western Power is

[545] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 8.

[546] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 8.4.

[547] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 15, paragraph 56 and 57.

[548] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, pp. 14-15, paragraph 55.

best placed to manage this risk as it is Western Power and not a User who approves (or does not approve) the connection of Generation Plant to its network.

- Further, the strict and continuing obligation is substantially more onerous than the provisions regarding compliance with the Technical Rules. For example, the User is not in breach of the Technical Rules where that breach by the User is caused by another party (except if the User is negligent or has not acted as a Reasonable and Prudent Person). In Synergy's view, Western Power's proposed provision for the ETAC is unreasonable and should not be approved by the Authority.

2234. Synergy considered the matters of proposed clause 13(c) should be addressed in the Technical Rules. Synergy noted that previous amendments to the rules made clear the requirements for modifications and the party responsible for inspecting and ensuring continued compliance.[549]

Role of Technical Rules

2235. Both Alinta and Synergy questioned whether the proposed changes to clause 13(c) were necessary, and if the matter Western Power was trying to address could be better dealt with in the Technical Rules.

2236. The Technical Rules consist of the standards, procedures and planning criteria governing the construction and operation of an electricity network. The rules also set out performance and technical specifications for user equipment connected to the network. The ERA is required to approve the Technical Rules that apply to the Western Power Network.[550] Exemptions from the rules are possible:

- Western Power may apply to the ERA for an exemption from one or more requirements of the Technical Rules for itself and all applicants, users and controller of its network.
- A user, applicant or controller may apply to Western Power for an exemption from one or more requirements of the approved Technical Rules.

2237. As to whether the requirements of clause 13(c) should be in the ETAC or the Technical Rules, the ERA was of the view that there was no reason why the requirements could not appear in both places, provided the requirements are not inconsistent.

2238. Western Power’s revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA’s draft decision. On that basis, the ERA maintains its draft decision.

Use of the words “materially modify” and “adversely impact”

2239. Synergy raised concerns over the use of the words “materially modify” (in clause 13(c)) and “adversely impact” (in clause 13(c)(ii)(B)).

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[549] Synergy, *AA4 Submission Number 2: Western Power’s proposed standard electricity transfer access contract*, 8 December 2017, p. 15, paragraph 58.

[550] The approved technical rules for the Western Power network are published on the ERA website at: https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules (accessed 8/1/2018)

2240. The ERA considered the words "adversely impact" did not require further clarification or explanation when used in conjunction with the phrase "the safety or security of the Network".

2241. Further, the changes to clause 13(i) were not significantly different to the existing clause 13(c)(i), which already included the phrase "materially modify". However, in the current form of drafting, to understand the meaning of "materially modify" in clause 13(c), the parties must refer to clauses 10.4 and 16.3 of the applications and queuing policy as they set out when an application is required; that is, whenever a modification changes "any of those characteristics of generating plant connected at a connection point required to be provided in the applicable application form".

2242. As the connection application form is not publicly available, the ERA considered that it would be clearer if the provisions in the ETAC and the applications and queuing policy were amended to expressly set out what are the characteristics of generating plant that, if changed, constitute material changes.

2243. The more significant change to clause 13 was the proposed inclusion of clause 13(c)(ii) to deal with material modification to generating plant that does *not* require an application under clause 10.4 of the applications and queuing policy. Given the unclear way in which clause 10.4 is drafted (by reference to an unidentified list of characteristics in an unpublished application form), it was not clear what sorts of modifications might be material but would not require an application. In the circumstances, the ERA required Western Power to amend clause 13(c)(i) to expressly set out the characteristics of generating plant that, if changed, would constitute material modifications for the purpose of that clause.

2244. Further, unless and until Western Power more clearly identifies what modifications are contemplated by clause 13(c)(ii) that would not fall within clause 13(c)(i), the ERA was of the view that the proposed insertion of clause 13(c)(ii) was contrary to the requirements of the Access Code.

2245. The ERA's draft decision required the following amendment to Western Power's proposal.

> **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.

2246. Western Power's revised proposal does not accept draft decision required amendment 48.[551]

> 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.

[551] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 222-223.

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.

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.

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.

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).

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.*

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.

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.

2247. Western Power proposes to maintain its initial proposed wording for clause 13(c) and proposes to add new clauses 13(d) and 13(e) as follows:

(d) For the purposes of clause 13(c)(ii) a modification is material only if:

(i) it involves expenditure of more than $100,000; or

(ii) the modification is one which, consistently with Good Electricity Industry Practice, requires review by a duly qualified engineer before being made.

(e) 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).

2248. In its submission on the draft decision, Synergy expressed its support for the ERA's draft decision required amendment 48.[552]

> A key operational and technical challenge for Synergy (and no doubt other users) is understanding precisely which of its and its customers' activities with respect to generating plant require WP's approval under the applications and queuing policy (AQP).
>
> Provided there is consistency between the SETAC and the AQP, Synergy agrees there is no benefit in establishing a clear threshold for the kind of modifications to generating plant required to be processed in accordance with the AQP.
>
> Synergy considers adequately specifying the characteristics of generating plant that, if modified, would constitute material modifications for the purpose of clause 13(c)(i) of the SETAC will greatly improve the likelihood the SETAC can be considered to form the basis of a commercially workable access contract. Given Synergy's position as the most significant user of network services in the SWIS, Synergy would appreciate the opportunity to make submissions on WP's consequent proposed amendments in order to confirm that WP's proposed amendments achieve the intent of the ERA's required amendment.
>
> Notwithstanding the desirability of adequately specifying generating plant characteristics as required by the ERA, Synergy also considers it necessary for the clause to provide for what "material modification" to those characteristics might constitute.
>
> For example, it is becoming increasingly common for Synergy's residential solar system owners to increase their panel and/or inverter size. This behaviour is being driven by reduced equipment costs, increased marketing and electricity price changes. In addition, the advent of battery and home vehicle recharge facility deployment will further accelerate such system modifications and investments.
>
> It is not clear, for example, if a customer connects a battery to their approved PV system to store and use excess electricity in their own home, whether that will constitute a material modification. It is also not clear if using excess electricity from the PV system to directly charge an electric vehicle constitutes a material modification.

2249. Synergy's concerns regarding adequately specifying generating plant characteristics as required by the ERA's required amendment for the clause to provide for what "material modification" to those characteristics might constitute have largely been addressed in new clause 13(d), albeit not to the level of detail suggested by Synergy. The addition of clause 13(e) seeks to provide additional clarity of what would not constitute a "material modification".

2250. The ERA considers the amendments are a reasonable compromise between the interests of Western Power and users. However, for clarity the words "Notwithstanding clause 13(d)," should be inserted at the start of clause 13(e).

2251. Western Power's proposed amendments to materiality in clause 13(d) and (e) and the additional amendment required by the ERA will satisfactorily address the concerns regarding the reasonableness requirement of section 5.3 of the Access Code and are sufficiently complete to form the basis of a commercially workable access contract.

[552] Synergy, Submission on draft decision, June 2018, pp. 48-49.

Required Amendment 46

Clause 13(e) of the electricity transfer access contract must read:

> "Notwithstanding clause 13(d) 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)."

Written notification period

2252. Western Power proposed a written notification period of 60 days under proposed clause 13(c)(ii)(A). Synergy noted that Western Power had not substantiated why it needed 60 days' notice prior to the anticipated modification and submitted that the notification period should be shorter.

2253. Western Power indicated that the obligation for the user to notify Western Power of a modification of its generating plant was to give Western Power the opportunity to raise any concerns it may have with the user before the modification is made. Accordingly, the notification period must be sufficient to enable Western Power to assess the impact of the proposed modification and to liaise with the user in relation to any concerns it may have.

2254. The ERA agreed with Synergy that Western Power had not substantiated why it needed a 60 day notification period. Similarly, Synergy had not substantiated why it thought the notification period should be shorter and had not suggested what the shorter notification period should be. Given these circumstances, and subject to clause 13(c)(ii) remaining in the ETAC (refer to paragraph 2244 above), the ERA considered a period of 30 days would be reasonable and that, if Western Power did require a longer period, it was to provide more information on what work it was proposing to undertake during the period to justify the length of period.

2255. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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.

2256. In its revised proposal, Western Power does not accept draft decision required amendment 49. It submits:[553]

> 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.
>
> 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.

[553] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 224.

2257. In its revised proposal, Western Power has not provided sufficient supporting information to substantiate its proposed notice period of 60 days. Although Western Power argues the types of modifications that fall within clause 13(c)(ii) are ones that will be made with significant prior planning it has failed to demonstrate the basis upon which one can objectively assess the reasonableness of the 60 days. Synergy's submission does not provide adequate substantiation for its preferred 30 day period.

2258. In the absence of convincing evidence to support either time period, the ERA considers that a period of 45 days is a reasonable period and balances the interests of the parties involved. The 45 day period satisfies the reasonableness requirement of section 5.3 of the Access Code and is consistent with the Code objective. This change in the notification period also affects clause 13(f) of the ETAC and is dealt with in the following section below.

Required Amendment 47

Clause 13(c)(ii)(A) of the electricity transfer access contract must be amended so the notification period is at least 45 days prior to the modification being made.

Obligations go beyond good electricity industry practice

2259. Synergy was concerned that proposed clause 13(c)(ii) broadened the current obligation of ensuring that a generating plant's design or installation was consistent with good electricity industry practice to an obligation on the user to ensure the modified generating plant does not adversely affect the safety or security of the network. Synergy claimed the practical effect of the change would result in Western Power allocating risk to users, which was not appropriate because Western Power was better placed to manage such risk (that is, it is Western Power that approves, or does not approve, the connection of generating plant to the network). The obligation was also substantially more onerous than the compliance provisions for the technical rules, which was unreasonable.

2260. As currently drafted, Western Power's amendments contemplate that a user will be obliged, under proposed clause 13(c)(ii), to notify Western Power of a modification to generating plant prior to the modification being made. Once notified, Western Power's submission suggested that it would then assess whether the modification to generating plant adversely affected the safety or security of the network, however this is not clear from Western Power's proposed clause. Western Power further suggested that if it formed the view that the modification would adversely affect the safety or security of the network, Western Power would raise these concerns with the user, however this is not clear from Western Power's proposed clause).

2261. Subject to clause 13(c)(ii) remaining in the ETAC (refer to paragraph 2244 above), clause 13(c)(ii) was to contain an express obligation for Western Power to notify the user within the notice period if it formed the view that the modification would have an adverse impact on safety or security, failing which the modification could proceed. Such an obligation was considered reasonable and formed the basis of a workable contract.

2262. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

2263. In its revised proposal, Western Power submits it has accepted draft decision required amendment 50 in principle with modifications:[554]

> 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.
>
> 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.

2264. Western Power proposes adding new clause 13(f) as follows:

> (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.

2265. No submissions were received on the draft decision.

2266. Other than the notification period the ERA considers Western Power's proposed amendment is reasonable and is satisfied it has complied with draft decision required amendment 50. However, the time period must be changed to 45 days to be consistent with clause 13(c)(ii) (refer to paragraph 2258 and required amendment 24 above).

Required Amendment 48

Clause 13(f) of the electricity transfer access contract must be amended so the notification period is at least 45 days prior to the modifications being made.

Other matters raised by interested parties

2267. Western Power did not propose any amendments to clause 13(a) of the ETAC. Mr Stephen Davidson, however, submitted that this clause should be amended to

[554] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 224.

include an obligation for the parties to record "all data required in the Technical Rules".[555]

2268. Clause 13(a) currently requires the parties to record:

- In Part 2 of schedule 3 (of the ETAC), any technical information that the user was required to provide to Western Power under the applications and queuing policy.
- In Part 3 of schedule 3, any exemptions to the Technical Rules given to the user under chapter 1 of the technical rules.

2269. The ERA considered that the intention behind clause 13(a) was to record the material pieces of technical information that form the basis on which the ETAC is agreed. For this reason, the user is required to provide, for example, the type of service (reference or non-reference service), the size or make of the generator (if applicable), the connection point and the facilities and equipment.

2270. Similarly, the agreed exemptions are material to the ETAC as it will affect whether the user is in breach of the Technical Rules and consequently clause 12.1 of the contract, which requires Western Power and the user to each comply with the Technical Rules. The ERA considered that this was all that is required to ensure that the ETAC is sufficiently detailed and complete to form the basis of a commercially workable access contract as required by clause 5.3(b) of the Access Code.

2271. The ERA considered it was not reasonable or necessary to require the parties to record further information beyond what is currently required in clause 13(a) of the ETAC.

2272. No further submissions were received on this matter in response to the ERA's draft decision.

Common provisions for limitation of liability and indemnity (clause 19)

2273. Clause 19 of the ETAC contains provisions covering liability and indemnity. Western Power proposed several changes to these provisions in the following areas, each of which are considered in turn below:

- limitation of liability
- apportionment of liability
- intermediary indemnity

2274. Alinta stated that it was broadly concerned with Western Power's changes to amend the network liability frameworks in favour of itself. Alinta was concerned that the proposed liability regime was unreasonably increasing the retailer's exposure, and as such, was not consistent with the objectives of the Access Code.[556]

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[555] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24),* 11 December 2017, Issue 23.

[556] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 8.3.

2275. The AEC raised concerns over Western Power's proposal "to amend network liability and insurance requirements in favour of itself". The AEC submitted that the proposal must be assessed to be consistent with the Access Code. It noted that the regulatory framework requires the ETAC to be reasonable, sufficiently detailed and complete to form the basis of a commercially workable contract.[557]

2276. Community Electricity noted the proposed changes to the liability provisions of the ETAC.[558] Community Electricity submitted that the network should be *fit-for-purpose* insured with the level of insurance properly determined. It considered Western Power should administer the insurance centrally and pass through the costs to users, and noted that Western Power largely chose to self-insure its liabilities (which were deemed to be a much lower figure).

2277. The ERA noted the positions of stakeholders in submissions on Western Power's proposed changes to clause 19 of the ETAC. Detailed considerations of these positions are outlined below.

Limitation of liability (clause 19.5(c))

2278. Clause 19.5(c) covers provisions for the limitation of liability. The existing provisions provide for the maximum liability amounts to be renegotiated every three years from the commencement date. The renegotiation is to be conducted in good faith and have regard to any relevant changed circumstances. Where the parties cannot agree the matter is to be determined as a dispute.

2279. Western Power submitted there are a number of problems with the existing provisions of clause 19.5(c):[559]

> Firstly the procedure is cumbersome and does not tend to be invoked. Secondly the provision is silent as to what caps apply pending the completion of negotiations or if the parties fail to agree. Thirdly a court is unlikely to be able to resolve such a dispute – the role of courts is to interpret agreed contracts not to resolve disputes as to failure to agree changes to contracts.

2280. Western Power proposed to change clause 19.5(c) to provide for liability caps to be escalated every three years to reflect the changes in the CPI. Western Power saw this change as "a simple unambiguous procedure for adjusting liability caps to ensure they remain appropriate given changes in the value of money".[560] The proposed change was as follows:

> (c) ~~At the end of each period of three Years from the Commencement Date, the Parties shall negotiate in good faith to re-set the maximum liability amounts applicable under clauses 19.5(a) and 19.5(b) having regard for any relevant changed circumstances in that period. If the Parties are unable to agree on re-setting of the maximum liability amounts, the matter shall be determined as a Dispute. The resolver of the Dispute is required to consider any changed circumstances during the period and adjust the maximum liability limit the subject of the Dispute to a reasonable limit, first having regard to the maintenance of the existing limit and then reducing or increasing the limit by reason of any relevant changed circumstances found to have occurred.~~The monetary caps on liability in this clause 19.5 will be CPI-

[557] Australian Energy Council, Submission on proposed revisions to Western Power's network access arrangement, 11 December 2017, pp. 1-2.

[558] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, pp. 12-13.

[559] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 9.

[560] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 9.

Adjusted every three years from the Commencement Date provided that for the purposes of such CPI adjustment the following formula will be used:

$$N = C\ x\ (1 + \frac{CPIn - CPIc}{CPIc})$$

where:

"N" is the new liability cap amount being calculated; and

"C" is the current liability cap amount being adjusted; and

"CPI_n" is the CPI applicable at the end of the calendar quarter ($quarter_n$) most recently ended prior to the adjustment date; and

"CPI_c" is the value of CPI applicable for the calendar quarter occurring 36 months before the calendar quarter referred to in the definition of CPI_n.

2281. The ERA considered that, consistent with Western Power's submission, the proposed changes would provide a simple unambiguous procedure for adjusting liability caps. However, the ERA considered that parties should be able to renegotiate the liability caps in the event that there is a material change to the underlying risk. The ERA required the following amendments to clause 19.5(c) and the insertion of a new clause 19.5(d):

(c) Subject to clause 19.5(d), ~~T~~the monetary caps on liability in this clause 19.5 will be CPI-Adjusted every three years from the Commencement Date provided that for the purposes of such CPI adjustment the following formula will be used:

$$N = C\ x\ (1 + \frac{CPIn - CPIc}{CPIc})$$

where:

"N" is the new liability cap amount being calculated; and

"C" is the current liability cap amount being adjusted; and

"CPI_n" is the CPI applicable at the end of the calendar quarter ($quarter_n$) most recently ended prior to the adjustment date; and

"CPI_c" is the value of CPI applicable for the calendar quarter occurring 36 months before the calendar quarter referred to in the definition of CPI_n.

(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.

2282. To support the proposed new clause 19.5(d) above, the term "material change" needed be added to the dictionary (at schedule 1 of the ETAC) to mean:

> 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.

2283. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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) as set out in paragraph 2281 above.
>
> 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 as set out in paragraph 2282 above.

2284. In its revised proposal, Western Power submits it has accepted draft decision required amendment 51 in principle with modifications:[561]

> 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.
>
> 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.

2285. The ERA agrees with Western Power that a reset of the monetary caps should only be triggered by external events. However, Western Power's revised definition is limited to any change to the regulatory environment or market structure – excluding other legitimate external events such as legislative requirements.

2286. The ERA requires the definition of Material Change be broadened to read "any change external to the party, including 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." This modified definition meets the requirements of section 5.3 of the Access Code and the Code Objective.

Required Amendment 49

The definition of material change in schedule 1 of the electricity transfer access contract must be amended to reflect the wording in paragraph 2286.

Apportionment of liability (clause 19.8)

2287. Clause 19.8 covers provisions for the apportionment of liability. The provisions provide for the apportionment of the indemnifier's liability where loss is partly caused by Western Power.

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[561] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 225.

2288. Western Power proposed to amend the clause to clarify that the provisions (of clause 19.8(a)) do not reduce the indemnifier's liability to indemnify Western Power for liabilities that the user has failed to discharge. The proposed amendments were as follows:

> 19.8 Apportionment of liability
>
> (a) ...
>
> (b) For the avoidance of doubt, where Western Power is liable to, or is to indemnify, either or both of the User or the Indemnifier under this Contract, the liability or indemnity owed by Western Power is limited to the proportion of the damage suffered by either or both of the User or the Indemnifier as a consequence of the Default, negligence or fraud of Western Power giving rise to the liability or indemnity.
>
> (c) For the purposes of the application of the indemnity given by the Indemnifier under clause 19.2(b):
>
> (i) clause 19.8(a) may apply to reduce the User's liability to Western Power and, consequently, the amount of liability for which the Indemnifier must indemnify Western Power;
>
> (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).

2289. Western Power considered the proposed amendments clarified the operation of clause 19.8 and did not disadvantage the indemnifier – the indemnifier got the benefit of any reduction in the user's liability by virtue of clause 19.8(a).[562]

2290. The ERA considered that, consistent with Western Power's submission, the proposed amendments clarified the operation of clause 19.8 and met the requirements of the Access Code, subject to minor drafting amendments to delete:

- The word *"the"* in clause 19.8(a), which was considered a typographical error (i.e. "…negligence or fraud of ~~the~~ either or both of the User or the Indemnifier giving rise to the liability or indemnity").
- The words *"under clause 19.2(b)"* in clause 19.5(c)(ii), which was considered unnecessary.

2291. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 52**
>
> Clause 19.8 of the electricity transfer access contract must be amended in accordance with paragraph 1388 of this draft decision [paragraph 2290 above] to make minor drafting amendments.

2292. In its revised proposal, Western Power has accepted draft decision required amendment 52 and has made the required amendments to clause 19.8.[563]

2293. No submissions were received on the draft decision.

2294. The ERA is satisfied that Western Power has complied with draft decision required amendment 52.

[562] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 10.

[563] Western Power, *Revised AA4 proposal: Response to the ERA's draft decision*, 14 June 2018, p. 226.

Intermediary indemnity (clause 19.11)

2295. Western Power proposed to add a new clause (19.11) to require the user, where they are an intermediary, to indemnify Western Power against any claims by the person for whom they act as intermediary. Western Power submitted that the new clause "avoids the agreed liability regime in the ETAC being circumvented by negligence claims against Western Power":[564]

> 19.11 Intermediary Indemnity
>
> Where:
>
> (a) the User is the Intermediary (as defined in the Market Rules) of a person; and
>
> (b) that person is not party to this Contract,
>
> then the User must indemnify and keep indemnified Western Power against any costs, expenses, losses or damages suffered or incurred by Western Power due to Claims made by that person against Western Power:
>
> (c) which Claims are in connection with the provision of the Services (including any failure of, or defect in provision of, the Services); or
>
> (d) which Claims relate to a matter for which Western Power's liability to that person would have been limited or excluded had that person been party to this Contract (jointly with the User).

2296. Synergy noted:[565]

> Clause 2.28.16A of the Market Rules provides if a person applies for an exemption from an obligation to register under the Market Rules as a "Rule Participant" in the "Network Operator" class, "Market Generator" class, "Market Customer" class, as an "Ancillary Service Provider", under clause 2.28.16 of the Market Rules, that person may in the application nominate a person to be registered instead of the applicant. That nominee is defined as an "Intermediary".

2297. Synergy submitted it had the following concerns with proposed new clause 19.11:[566]

- To be the Intermediary of a person, it is not necessary the application for exemption described above be approved, simply that a nomination be made in an application that is submitted. This means clause 19.11 would operate to capture Users that are not registered on behalf of an exempted party because an application may have been withdrawn or been rejected by the Australian Energy Market Operator. This could give rise to a situation where a User is required to provide this indemnity despite having no contractual or other relationship with that third party.

- The exclusion of Indirect Damage provided in clause 19.3(b) is unlikely to apply to the indemnity because clause 19.11 clearly indicates the subject of the indemnity is "any costs, expenses, losses or damages suffered or incurred", all of which are likely to be costs, expenses, losses or damages in the nature of Indirect Damage. If the exclusion in clause 19.3 applies, then clause 19.11 will have no work to do; it therefore seems the intention is for clause 19.11 to have a similar effect as the phrase "the exclusion of Indirect Damage in clause 19.3 does not apply".

[564] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 11.

[565] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 16, paragraph 60.

[566] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 16, paragraph 61.

- This means a User would be liable for this class of costs arising in respect of Claims made by the third party against Western Power which are in connection with the provision of the Services or which relate to a matter for which Western Power's liability would have been limited or excluded had that person been party to the ETAC. "Claims" is defined in the ETAC to mean "any claim, demand, action or proceeding made or instituted against a Party". Use of the ETAC defined term "Claim" makes it clear the indemnity will be activated in relation to a broad range of triggers and is intended to cover a broad range of costs, with only the liability cap of $80 million, indexed, set out in clause 19.5 to apply as a cap.
- Finally, Synergy's position is the Controller provisions contained at clause 6 of the ETAC are not sufficiently robust to address WP's legitimate business interests in respect of third party claims. Those provisions require the User to procure a Controller releases Western Power from claims, which Western Power can then enforce under section 11 of the *Property Law Act 1969 (WA)*.
- The indemnity set out in clause 19.11 is not reasonable, and as such inconsistent with section 5.3(a) of the Access Code. It also fails to form the basis of a commercially workable access contract in breach of section 5.3(b) of the Access Code.
- The provision is also inconsistent with the Access Code objective.

2298. The ERA considered Synergy's concern that the intermediary may not be registered as a rule participant under the Market Rules could be addressed by amending clause 19.11(a) to add the words "and in so far as they are registered as a Rule Participant (as defined in the Market Rules)" after the word "person". That is:

> 19.11 Intermediary Indemnity
>
> Where:
>
> (a) the User is the Intermediary (as defined in the Market Rules) of a person and in so far as they are registered as a Rule Participant (as defined in the Market Rules); and

2299. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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 as set out in paragraph 2298 above.

2300. In its revised proposal, Western Power submits it accepts draft decision required amendment 53 in principle with modifications:[567]

> 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:
>
> …
>
> Where:
>
> (a) the User is registered under the Market Rules as the Intermediary (as defined in the Market Rules) of a person; and

2301. In its submission on the draft decision, Synergy submits:

[567] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 226-227.

The ERA's required amendment is that WP change clause 19.11 to read "the user is the Intermediary (as defined in the Wholesale Electricity Market Rules (Market Rules) of a person and in so far as they are registered as a Rule Participant (as defined in the Market Rules)". For the purpose of these submissions, Synergy refers to this nominating party as the "Nominator".

Synergy's view is that, if clause 19.11 of the SETAC is approved in the form determined in the ERA's draft decision, a user on a legacy ETAC or negotiated access contract is free to act as an Intermediary under the Market Rules without being required to agree to clause 19.11 of the SETAC. Only new ETACs in the form of the SETAC agreed between WP and users will have the clause.

The ERA considers one of Synergy's concerns with respect to clause 19.11 is the person nominated to be an Intermediary may not be registered as a rule participant under the Market Rules. In fact, Synergy's concern is more specific: it is not that the person nominated to be an Intermediary is not registered as a rule participant but the person must be registered as a rule participant in respect of that application. This clarification is necessary because a party who is a rule participant prior to any application being made will still inadvertently be caught by the definition if the application is made without that party's consent or if the application is rejected by AEMO. As drafted, the ERA's proposed amendment is therefore only effective in circumstances where an applicant is made in respect of a party who is not already registered as a rule participant under the Market Rules.

To effect a more specific amendment to address this remaining risk, Synergy proposes the following amendment to the drafting (Synergy's amendments in underline):

"the user is the Intermediary (as defined in the Market Rules) of a person, and in so far as they are registered as a Rule Participant (as defined in the Market Rules) and to the extent they perform the functions of an Intermediary".

In response to Synergy's concerns with respect to the scope of the indemnity in proposed new clause 19.11 of the SETAC, the ERA considers it is a legitimate business interest of WP to protect itself against third party claims in instances where a third party is not a party to the contract resulting in WP being unable to receive the benefit of any reduced liability under that contract. The ERA further considers that Synergy's concerns can be addressed by the user requiring a third party to enter into the same exclusion of indirect damage provisions as set out in the contract as a precondition to the user agreeing to act as an intermediary under the Market Rules.

Synergy acknowledges the ERA's suggestion is one mechanism available to address the risks associated with proposed clause 19.11 that would not solely apply to it but also other users. However, in Synergy's submission, while it may be in WP's legitimate business interests to seek to minimise the effect of third party claims by seeking to impose a broad indemnity on users in respect of Nominators, such an indemnity should not be approved by the ERA.

This is because the indemnity will have the effect of disadvantaging all users on the SETAC compared to users on legacy access contracts. It will do so because only the latter party will be required to:

- adopt risk allocation mechanisms to address the indemnity by, for example, excluding liability for indirect damages and/or capping liability at the caps set out in the SETAC; and/or
- obtain specific insurance coverage to address the risk associated with the indemnity, which may require a particular extension of cover given the breadth of the indemnity.

In either case, the risk externalised by WP by virtue of clause 19.11 on users under the SETAC will result in affected users incurring costs that are not borne by users on legacy access contracts, including Synergy. Those costs are, in essence, a competitive disadvantage in the context of commercial arrangements associated with being an Intermediary under the Market Rules.

> If, in contrast, that risk applies to WP then presumably it would procure appropriate insurance to address it or self-insure for an amount equivalent to the risk. In either case the cost of that insurance or self-insurance would, subject to the ERA's approval, be shared amongst all users to the extent it actually represents an increased risk position relative to that WP presently carries.
>
> In Synergy's view, the latter course would be a more economically efficient outcome and would better promote the Access Code objective because it would avoid imposing a competitive disadvantage among users that are party to the SETAC; users that are in Synergy's estimation more likely to be new entrant businesses. Accordingly, the ERA must determine whether WP's proposal will facilitate competition upstream and downstream of the networks in accordance with the Access Code objective.
>
> Further, such an outcome would also be consistent with the matters the ERA is required to have regard to under section 26(1) of the ERA Act, including:
>
> - the long-term interests of consumers in relation to the price, quality and reliability of goods and services provided in relevant markets;
> - the need to encourage investment in relevant markets;
> - the legitimate business interests of investors and service providers in relevant markets;
> - the need to promote competitive and fair market conduct; and
> - the need to prevent abuse of monopoly or market power.
>
> However, if the ERA is minded to approve new clause 19.11 notwithstanding Synergy's submissions, and the ERA's rationale for doing so remains broadly consistent with that described in [ERADD 1393] of the draft decision, Synergy considers the indemnity should only apply in respect of any costs, expenses, losses or damages suffered or incurred by WP that WP **would not have suffered or incurred were the Nominator a party to a SETAC. (Emphasis added)**

2302. Synergy considered that this approach more accurately reflected Western Power's position under the standard access contract and, accordingly, its legitimate business interests, consistently with the ERA's reasoning at paragraph 1393 of the draft decision.

2303. The ERA agrees with Synergy that the ERA's draft decision required amendment would only be effective in circumstances where an application is made in respect of a party who is not already registered as a rule participant under the Market Rules. The ERA agrees it is necessary to amend clause 19.11(a) as follows: "the user is the Intermediary (as defined in the Market Rules) of a person, and in so far as they are registered as a Rule Participant (as defined in the Market Rules) and to the extent they perform the functions of an Intermediary".

> 19.11 Intermediary Indemnity
>
> Where:
>
> (a) the User is the Intermediary (as defined in the Market Rules) of a person and in so far as they are registered as a Rule Participant (as defined in the Market Rules) <u>and to the extent they perform the functions of an intermediary</u>; and

2304. This requires that the person must be registered as a rule participant in respect of that application - otherwise, a party who is a rule participant prior to any application being made will still inadvertently be caught by the definition if the application is made without that party's consent or if the application is rejected by AEMO. The ERA considers this would be unreasonable and requires the following amendment.

Required Amendment 50

Clause 19.11(a) of the electricity transfer access contract must be amended in accordance with paragraph 2303 of this final decision.

2305. Synergy's secondary concern was that a user acting as an intermediary for a third party under clause 19.11 was liable for any indirect damage caused and that this would not be the position if that third party were a party to the contract. The ERA considered that it was reasonable and consistent with clause 5.3 of the Access Code to accept clause 19.11. This was because, in accordance with section 26(1)(d) of the *Economic Regulation Authority Act 2003*, the ERA considered it to be a legitimate business interest of Western Power to protect itself against third party claims in the instance where the third party was not a party to the contract, resulting in Western Power being unable to receive the benefit of any reduced liability under that contract. Synergy's concerns could have been addressed by the user requiring the third party to enter into the same exclusion of indirect damage provisions as set out in the contract as a precondition to the user agreeing to act as an intermediary under the Market Rules.

2306. Synergy proposes that if the ERA is minded to approve new clause 19.11, the indemnity should only apply in respect of any costs, expenses, losses or damages suffered or incurred by Western Power that Western Power "would not have suffered or incurred were the Nominator a party to a SETAC".

2307. If the Nominator was a party to the SETAC, Western Power would not be liable for any Indirect Damage suffered by the Nominator save where expressly provided in the SETAC. This is essentially the same position that Western Power is placed in as a result of clause 19.11(d). In the circumstances, the ERA does not consider that any further amendment is required to the text of clause 19.11(d). The ERA remains of the view that it is within the user's power to protect its position in its contract with the intermediary.

Other matters raised by interested parties

2308. Mr Stephen Davidson submitted that further changes to clause 19 of the ETAC should be considered:[568]

- The liability limit of $5 million under clause 19.5(a) was too low – it should not be capped below $500 million.
- For recoveries under insurance, clause 19.10, negligence should be excluded, not included (that is, "including" to be "excluding").

2309. The ERA considered that there was no reason to vary clause 19 of the ETAC as suggested by Mr Davidson. Without any information provided to the contrary, the current liability limit is reasonable and forms part of a commercially workable access contract in accordance with clause 5.3 of the Access Code. Similarly, the ERA

[568] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24),* 11 December 2017, Issue 23.

considered there was no reason to change clause 19.10 as the intention of this clause was to apply to claims that include negligence in order to protect the user and the indemnifier from paying Western Power in respect of a claim to the extent Western Power has already recovered its losses under its insurance policy.

2310. Community Electricity submitted that the following changes relating to clause 19(5)(b) of the ETAC should be considered:[569]

- The maximum liability limits did not reflect the nature of different users – they were not fit for purpose.
- There was a lack of availability of information as to how Western Power assesses its liability risk.

2311. The current drafting in clause 19.5(b) is consistent with clause 5.3 of the Access Code. The ERA considered that it was reasonable (and forms the basis of a commercially workable access contract) for Western Power to protect its asset profile.

2312. The ERA also gave consideration to the matter in section 26(1)(d) of the *Economic Regulation Authority Act 2003* and considered it to be a legitimate business interest of a service provider to require insurance against the risk of connection to the South West Interconnected System (SWIS). Western Power raised concern in the response provided to Community Electricity that "regardless of the size of the contract the risk of a connection into the SWIS remains unchanged".[570]

2313. No submissions were received on this matter in response to the draft decision.

Common provisions for notices (clause 35)

2314. Clause 35 of the ETAC contains provisions for notices. Western Power proposed to make changes to this clause to update:

- the requirements for communications
- when communications are deemed to be received.

Requirements for communications (clause 35.1)

2315. Existing clause 35.1 provides for communications to be delivered or sent by *ordinary letter post* and also by *facsimile transmission*. Western Power proposed to:

- Update clause 35.1(b)(ii) to change the reference to ordinary letter post to *priority post*, which reflects Australia Post's revised (current) postal services.
- Delete clause 35.1(b)(iv) that currently allows for communications being given by facsimile transmission.

2316. No submissions on Western Power's initial proposal addressed this matter. The ERA considered the proposed amendments were reasonable and reflected the changes to the postal system in Australia and the decline in the usage of facsimile transmissions.

[569] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, pp. 12-13.
[570] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, p. 13.

2317. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains the view that the proposed amendments were reasonable and reflected the changes to the postal system in Australia.

Communications sent by fax (existing clause 35.4(c))

2318. Clause 35.4 sets out the circumstances when communications are deemed to be received under the contract. Western Power proposed to delete existing clause 35.4(c), which outlines when a communication sent by facsimile transmission is deemed to be received.

2319. Western Power's proposal to delete existing clause 35.4(c) from the ETAC was a consequential amendment to the deletion of clause 35.1(b)(iv), which is addressed above at paragraph 2315.

Other consequential changes

2320. The ERA required the following consequential amendments that arise from the deletion of clause 35.1(b)(iv), which is addressed above (at paragraph 2315):

- Clause 1.1(d) provided that the word "copy" includes "a facsimile copy, photocopy or (subject to the Electronic Communications Protocol in Schedule 7) electronic copy". The words "facsimile copy" were to be deleted.
- Clause 36 set out the circumstances when a party may designate a change of email, postal address or facsimile number for the purposes of the notice provisions. The word "facsimile number" was to be deleted.
- Schedule 6 set out the notice details of each party. The words "facsimile number" from Part 1 and Part 2 of the table were to be deleted.

2321. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

2322. In its revised proposal, Western Power has accepted draft decision required amendment 54 and has made the required consequential amendments.[571]

2323. No submissions were received on the draft decision.

2324. The ERA is satisfied that Western Power has complied with draft decision amendment 54.

[571] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 227.

Miscellaneous provisions (clause 37)

2325. Clause 37 of the ETAC contains various miscellaneous provisions, including remedies. Existing clause 37.13 provides that the rights, powers and remedies under the contract are cumulative with and not exclusive of the rights, powers or remedies provided by law independently of the contract.

2326. Western Power proposed to amend clause 37.13 to clarify that common law termination rights do not apply under the ETAC. It submitted that:[572]

> Common law termination rights are vague and difficult to apply. They do not necessarily allow for a cure period which would contradict the direct intent of clause 27 which is to give both parties an opportunity to cure defaults. Reinforcing that rights to terminate are to be solely determined in accordance with clause 27 is consistent with the historical understanding of how the ETACs operate.

2327. The proposed amendments were as follows:

> 37.13 Remedies
>
> (a) Subject to clause 37.13(b), t~~T~~he rights, powers and remedies provided in this Contract are cumulative with and not exclusive of the rights, powers or remedies provided by L~~l~~aw independently of this Contract.
>
> (b) A Party may only terminate this Contract in circumstances permitted by express provisions of this Contract. Any rights to terminate this Contract at common law are excluded.

2328. No submissions on Western Power's initial proposal addressed this matter.

2329. Western Power's proposal to amend clause 37.13 was consistent with the requirements of the Access Code – the proposal was reasonable and reinforced that the right to terminate is confined to the matters listed in clause 27 of the contract (which are acceptable grounds for termination).

2330. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2329 above. The amendment is consistent with section 5.3 in that it is reasonable and sufficiently detailed and complete and consistent with the Code objective.

Dictionary (schedule 1)

2331. Schedule 1 of the ETAC contains the dictionary of defined terms. Western Power proposes to make changes to the defined terms "insolvency event" and "wilful default".

Insolvency event

2332. Western Power submitted that the existing definition of "insolvency event" was confusing. It proposed to amend the definition to clarify that a party was insolvent if they were insolvent within the meaning of section 95A of the *Corporations Act* and

[572] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 13.

that the scheme referred to in paragraph (c) was a *solvent* scheme.[573] The proposed amendments were as follows:

> Insolvency Event
>
> in respect of a Party, means any one or more of:
>
> (a) ~~any suspension or cessation to payment of all or a class of its debts by an~~ the Party is insolvent within the meaning of section 95A of the Corporations Act; or
>
> (b) any execution or other process of any court or authority being issued against or levied upon any material part of that Party's property or assets; or
>
> (c) a petition or application being presented (and not being withdrawn within 10 Business Days) or an order being made or a resolution being passed for the winding up or dissolution without winding up of that Party otherwise than for the purpose of reconstruction or amalgamation under a solvent scheme; or
>
> (d) …

2333. No submissions on Western Power's initial proposal addressed this matter.

2334. The ERA considered Western Power's proposed changes to the defined term "insolvency event" were reasonable and improved the clarity of the definition. The deletion of words in paragraph (a) replicated the language in section 95A of the *Corporations Act* and the addition of the word "solvent" in paragraph (c) clarified that an "insolvency event" would not arise when an application is made for the purposes of a solvent scheme of arrangement. A solvent scheme of arrangement is used by insurance companies to restructure a business while the business is still solvent.

2335. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2334 above.

Wilful default

2336. Western Power proposed to amend the definition of "wilful default" to fix a drafting error – the words "a deliberate and purposeful act or omission carried out with" was to form a lead in sentence that applies to both paragraphs (a) and (b) as follows:

> Wilful Default
>
> means a deliberate and purposeful act or omission carried out with:
>
> (a) ~~a deliberate and purposeful act or omission carried out with~~ a calculated regard for the consequences of the act or omission; or
>
> (b) a reckless or wilful disregard for the consequences of the act or omission,
>
> but does not include any error of judgment, mistake, act or omission, whether negligent or not, which is made in good faith.

2337. The proposed amendment to the definition of wilful default was administrative in nature and corrected an existing drafting error.

2338. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's

[573] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 13.

draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2337 above.

Other matters raised by interested parties

2339. Mr Stephen Davidson submitted that the definition of force majeure was to be amended to delete the following events or circumstances. Mr Davidson noted that the “ATO disallows speeding fines as taxable deductions to individuals [and] corporations should not be able to pass on the cost of own wrong-doing onto the consumers”:[574]

- Delete inclusion “(c) any award of any court or tribunal…”
- Delete inclusion “(i) any application of any law …”

2340. The ERA considered that the current definition of force majeure was appropriate, conformed to common business practice, and therefore formed the basis of a commercially workable access contract in accordance with clause 5.3(b) of the Access Code. Specifically, the current paragraphs (c) and (i) of the definition of force majeure are reasonable as they protect the parties in the event that performance is prevented due to circumstances beyond the parties' control. As these circumstances are many and varied it is reasonable for the definition to be broad as possible. It was deemed appropriate that paragraph (c) relating to binding decision and paragraph (i) relating to change in law be retained. This was to both parties' benefit.

2341. Mr Davidson’s particular concern related to a party's wrongdoing. This would be a matter in the party’s control and therefore would not meet the definition of force majeure.

2342. No submissions were received on this matter in response to the draft decision.

Other proposed changes

Deleting references to expiration (clauses 9(f) and 33.8)

2343. Western Power proposed to remove references to *expiration* in the ETAC. There are currently two clauses in the contract that contain such references:

- Clause 9(f) provides for security to be returned to the user upon the *expiry* or termination of the contract.
- Clause 33.8 provides for the return of all documents containing the other party’s confidential information to be returned to the other party upon the termination or *expiration* of the contract.

2344. Western Power submitted that when referring to the end of the ETAC elsewhere in the contract only the term *termination* is used (see for example clauses 19.7, 28, 33.10 and 37.12). Use of the term *expiration* may suggest the other references are only intended to capture early termination and not expiry, which is incorrect.[575]

2345. Western Power proposed to delete the reference to *expiry* in clause 9(f) and to delete the reference to *expiration* in clause in 33.8 as follows. It considered the

[574] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24),* 11 December 2017, Issue 23.

[575] Western Power, *Access arrangement information: Attachment 12.1*, 2 October 2017, p. 12.

amendments were "legal clarification" and did "not make any substantive change to the parties' rights":

> 9. Security for Charges
>
> …
>
> (f) Upon the ~~expiry or~~ termination of this Contract…
>
> 33.8 Return of materials
>
> Subject to any obligation under any Law relating to records retention and subject to prudent recording – keeping procedures (including, in contemplation of potential legal action), a Party must return all documents containing the other Party's Confidential Information, including all copies, to the other Party on termination ~~or expiration~~ of this Contract, or, upon request by the other Party, destroy all such documents.

2346. No submissions on Western Power's initial proposal addressed this matter.

2347. The ERA considered Western Power's proposed changes to remove references to expiration in the ETAC were reasonable and did not substantially alter the parties' rights.

2348. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2347 above.

Minor changes

2349. Western Power made a number of other corrections throughout the ETAC.[576] These corrections include typographical, grammatical, cross-referencing and other referencing corrections.

2350. Synergy noted that Western Power had made a number of minor amendments throughout the ETAC, including to capitalise certain words/terms. Part 1(a)(i)(A) of schedule 5 included an amendment to capitalise of the word "claims" in relation to the insurances the user must procure under clause 21 of the ETAC as follows:

> Part 1 User insurances
>
> (a) The User must effect and maintain, commencing from the Commencement Date the following policies of insurance:
>
> (i) public and products liability of:
>
> (A) 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

2351. Synergy considered that the capitalisation greatly expands the scope, and consequently the cost, of insurance cover to Western Power's benefit from a "claim" (which applies when the term is not capitalised) to "any claim, demand, action or

[576] The individual corrections made by Western Power are shown in the marked-up copy of the ETAC provided with Western Power's proposed revised access arrangement.

proceeding made or instituted against a party" (which applies when the term is capitalised). Synergy submitted:[577]

> Western Power provided no rationale for making [the] change. Nor is Synergy aware of any legitimate basis for why the scope of Users' insurance obligations and hence Users' liability to Western Power under the ETAC, should be so expanded.
>
> In the absence of any justifiable rationale for the amendment, Synergy considers the proposed clause is not reasonable and is therefore inconsistent with clause 5.3(a) of the Access Code. Nor is Western Power's proposed amendment, being that its basis has not been clarified, consistent with the need to promote transparent decision-making processes that involve public consultation and as such the provision is inconsistent with section 26(1)(g) of the ERA Act.
>
> Other capitalisations of terms give rise to circular definitions or awkward meanings – for example the circular definition created by using the term "Default" in the definition of Default at clause 27.1, or the capitalisation of "Contract" in clause 6.2(b), which amendment means the User and Controller must enter into the ETAC between the User and Western Power, which cannot have been Western Power's intention.

2352. The ERA considered Synergy's concerns in relation to the capitalisation of certain words/terms to be valid. Detailed considerations of each word/term, where such a change was made, are outlined below.

"Claim"

2353. The ERA agreed with Synergy that without capitalisation the word "claim" is taken to mean a legal assertion or demand. However through capitalisation the word is significantly broadened to also include actions and proceedings. Whether such broadening is appropriate will depend on the clause in which it is used.

2354. The capitalisation of the word "claim" in proposed new clause 19.11 was appropriate. The ERA considered that, similar to clause 19.6 of the standard access contract, Western Power was entitled to be indemnified against claims, including actions and proceedings. However, the ERA considered that the proposed capitalisation of the word "claim" in Part 1 of schedule 5 of the ETAC to be unfair. This was because Western Power is not also subject to capitalised *claims* in Part 2 of schedule 5. Therefore, the ERA considered that the proposed change was inequitable and unreasonable and did not promote a fair market.

2355. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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"

2356. In its revised proposal, Western Power has accepted draft decision required amendment 55 and has made the required amendments to Part 1 a(a)(i)(A) of schedule 5.[578]

[577] Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 17, paragraphs 65-67.

[578] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 228.

2357. No submissions were made on the draft decision.

2358. The ERA is satisfied that Western Power has complied with draft decision amendment 55.

Clause 6.2 – "contract"

2359. Western Power had incorrectly capitalised the word *contract* in clause 6.2(b). The intention of this clause is to require the user to enter into a contract with the controller that requires the controller to comply with the obligations set out in the ETAC. Accordingly, clause 6.2(b) was required to be amended as follows (a minor grammatical amendment to include the word *any* was to be taken into account):

> 6.2 Where the User is not the Controller
>
> …
>
> (b) If the User is not the Controller of a Connection Point, and the Controller of that Connection Point has not entered into a Connection Contract with Western Power in respect of the Connection Point, then the User must ensure that it enters into a ~~C~~contract with the Controller obliging the Controller to comply with the obligations set out in this Contract (to the extent set out in clause 6.2(a)) and that any such ~~C~~contract entered into between the User and a Controller relating to Services under this Contract contains a provision:
>
> (i) that neither the User nor Western Power is …
>
> (ii) under which the Controller covenants …
>
> The exclusion of Indirect Damage in clause 19.3 does not apply to a failure by the User to ensure that its ~~C~~contract with the Controller contains the covenant referred to in paragraph (ii) above.

2360. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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 as set out in paragraph 2359 above.

2361. In its revised proposal, Western Power has accepted draft decision required amendment 56 and has made the required amendments to clause 6.2(b).[579]

2362. No submissions were made on the draft decision.

2363. The ERA is satisfied that Western Power has complied with draft decision required amendment 56.

Clause 7.1 – "tariff" and "consumption"

2364. The proposed changes from the word "tariff/s" to "Tariff/s" in clause 7.1 were incorrect and should not have been made. "Tariff" is defined in the standard access arrangement as having the meaning in clause 7.1. For this reason it was appropriate

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[579] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 228.

that the word *tariff* was not capitalised in most instances in that clause so that the definition of "tariff" was not circular.

2365. The change to capitalise the word "consumption" was also incorrect and should not have been made. The definition of "consumption" in the standard access contract is in relation to the "connection point" which is specific to the parties to the contract. In contrast, the reference to *consumption* in clause 7.1 related to tariffs in the Price List which applied to the access arrangement as a whole and was not specific to the parties to the contract.

2366. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 as set out in paragraphs 2364 and 2365 above.

2367. In its revised proposal, Western Power has accepted draft decision required amendment 57 and has made the required amendments to clause 7.1.[580]

2368. No submissions were made on the draft decision.

2369. The ERA is satisfied that Western Power has complied with draft decision required amendment 57.

Clause 9 – "taxes"

2370. Changing the word "Taxes" to lower case "taxes" in clauses 9(f), 9(i) and 9(j) was considered appropriate given that *taxes* was not defined in the dictionary at Schedule 1 of the ETAC.

Clause 9 and Schedule 5 Part 1 (a)(iii) – "services"

2371. Changes made to capitalise the word "service/s" in clause 9 of the ETAC were appropriate. Clause 9 requires security equal "to the Charges for two month's services". "Charges" was defined to relate to the capitalised word "services" which includes (entry, exit and bidirectional services). As there are no other services for which a "charge" can apply to, it was appropriate for the word *services* to be capitalised. As previously discussed (at paragraph 2224 above), there was a drafting error in the proposed amendments to clause 9(i) as the first instance of the word "service" was not capitalised.

2372. Similarly, the capitalisation of the word "services" in Part 1 of schedule 5 was appropriate. It was the intention of Part 1 that the public liability insurance covers the specific services as provided and defined under the contract.

Clause 12.2 – "user" and "party"

2373. The change made to clause 12.2 to capitalise the word "user" was incorrect and was not accepted. The capitalised term "User" refers to the specific parties to the contract. In contrast, the "user" referred to in clause 12.2(e) was to another *user* who is not a "party" to the contract. Similarly the capitalisation of the word "party" in

[580] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 228.

clause 12.2(f) was also incorrect and was not accepted. Again, the reference to "party" in this clause was to another person (or *party*) who was not subject to the contract.

2374. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 as set out in paragraph 2373 above.

2375. In its revised proposal, Western Power has accepted draft decision required amendment 58 and has made the required amendments to clause 12.2.[581]

2376. No submissions were made on the draft decision.

2377. The ERA is satisfied that Western Power has complied with draft decision amendment 58.

Clause 18.1(a)(iv) – "related bodies corporate"

2378. The changes made to clause 18.1(a)(iv) to capitalise the term "related bodies corporate" were correct and consistent with the dictionary of defined terms at schedule 1 of the ETAC.

Clause 19 and clause 35.4(d) – "party/parties"

2379. The changes made to clause 19.1, clause 19.6 and clause 35.4(d) to capitalise the word "party" were incorrect and should not have been made. The terms "Party" and "Parties" are defined in schedule 1 of the ETAC to mean "Western Power or the User" and "Western Power and the User" respectively. Clauses 19.1, 19.6 and 35.4(d) are intended to apply to the user, Western Power *and* the indemnifier. It is for this reason the word "party" (or "parties") was not to be capitalised in these clause.

2380. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 as set out in paragraph 2379 above.

2381. In its revised proposal, Western Power has accepted draft decision required amendment 59 and has made the required amendments to clauses 19.1, 19.6 and 35.4(d).[582]

2382. No submissions were made on the draft decision.

2383. The ERA is satisfied that Western Power has complied with draft decision required amendment 59.

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[581] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 229.

[582] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 229.

Clause 27.1 – “defaults”

2384. Changes made to clause 27.1 to capitalise the word "default" were incorrect and should not have been made. “Default” is defined to have the meaning in clause 27.1 of the ETAC. It is for this reason that *default* should have been left uncapitalised so that the definition is not circular.

2385. The ERA’s draft decision required the following amendment to Western Power’s proposal.

> **Draft Decision 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 as set out in paragraph 2384 above.

2386. In its revised proposal, Western Power has accepted draft decision required amendment 60 and has made the required amendments to clause 27.1.[583]

2387. No submissions were made on the draft decision

2388. The ERA is satisfied that Western Power has complied with draft decision required amendment 60.

Schedule 5 Part 1 (a)(iii) – “works”

2389. The change made to Part 1(a)(iii) of schedule 5 of the ETAC to capitalise the word "works" was appropriate. It was the intention of Part 1 that the public liability insurance covered the specific works as provided and defined under the contract.

Other existing clauses

2390. Submissions on Western Power’s initial proposal included comments on existing clauses of the ETAC, for which no amendments were proposed. The ERA’s considerations in its draft decision on these clause are set out below.

Clause 12.1 – Western Power and the user must comply

2391. Clause 12.1 of the ETAC requires Western Power and the user to each comply with the Technical Rules. Mr Stephen Davidson objected that there is no financial penalty provisions in the ETAC for non-compliance with this clause.[584]

2392. The ERA considered that it would be somewhat onerous to attempt to impose a specific financial penalty for a breach of the Technical Rules because there may be more than one user responsible for the breach. The process to ascertain the extent to which any users’ breach caused or contributed to a loss and consequently how the penalty should be apportioned would be complex. Furthermore, a breach of the Technical Rules may ultimately cause no *actual* loss to Western Power so a financial penalty may be inappropriate. In these circumstances the usual remedies for breach of contract (including termination or damages) were considered appropriate and reasonable and form the basis of a commercially workable contract.

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[583] Western Power, Revised AA4 proposal: Response to the ERA’s draft decision, 14 June 2018, p. 229.

[584] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24),* 11 December 2017, Issue 23.

2393. No submissions were received on this matter in response to the draft decision.

Clause 18.2 – Western Power's representations and warranties

2394. Mr Davidson further submitted that clause 18.2(a)(ii) should be amended to include an obligation whereby "Western Power warrants that it has complied with the Technical Rules in respect of the Application" (or to that effect).[585]

2395. Without further explanatory information from Mr Davidson on this point, the ERA had no basis for considering this change or why it is required.

2396. No submissions were received on this matter in response to the draft decision.

Clause 22 – Force majeure

2397. Synergy submitted that clause 22 of the ETAC should be amended as follows:[586]

> The reporting standard on the Affected Person in clause 22.3(a) should 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";
>
> In relation to clause 22.4 of the ETAC, an Affected Person should not be obliged to incur any expenditure in complying with clause 22.3(b) if the Force Majeure Event is constituted by a breach of, or a failure to comply with, either of the ETAC or the Metering Code. Synergy considers that reference to the Metering Code ought to be incorporated into clause 22.4 of the ETAC.

2398. Clause 22 of the ETAC contains various force majeure provisions. The ERA considered that Synergy's proposed amendment to clause 22.3(a) was reasonable and would improve the workability of the access contract. For this reason Synergy's proposed change was accepted.

2399. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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".

2400. In its revised proposal, Western Power has not accepted draft decision required amendment 61. It submits:[587]

> 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.
>
> 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.

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585 Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24),* 11 December 2017, Issue 23.

586 Synergy, *AA4 Submission Number 2: Western Power's proposed standard electricity transfer access contract*, 8 December 2017, p. 17, paragraph 69.

587 Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 230.

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.

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.

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.

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.

2401. Western Power's desire to give priority to restoring power in the event of an outage and during critical emergencies is understandable and appropriate. However, to ensure consistency with clause 5.3 of the Access Code and the Code Objective, "forming the view" should be replaced with "becoming aware that" and notices should be issued within 5 business days to ensure timely notification to users.

2402. The ERA's final decision requires the following amendment to Western Power's proposal.

Required Amendment 51

Clause 22.3(a) of the electricity transfer access contract must be amended to read:

"A notice under clause 22.3(a) must be given as soon as reasonably practicable and in any event within 5 Business Days of a Party becoming aware an event is or is likely to be a Force Majeure Event."

2403. Without further explanatory information from Synergy on why a failure to comply with the Metering Code was to be incorporated into clause 22.3(b), the ERA had no basis for considering this change or why Synergy considered it was required.

2404. Synergy has not provided any further details on this matter in response to the ERA's draft decision and hence, the ERA maintains this view.

Schedule 3 – Details of connection points

2405. Mr Stephen Davidson submitted that schedule 3 of the ETAC is inconsistent with the data requirements of the Technical Rules. Mr Davidson considered the full schedules of the Technical Rules should be included in schedule 3 of the ETAC for loads and generators, if on-site generation was present.[588]

2406. The ERA did not receive sufficient information in Mr Davidson's submission (or from any other interested party) to justify why such an amendment was needed. Absent this information, the ERA has no basis for considering such a change. In any case, the ERA considered such a change may be overly onerous.

2407. No submissions were received on this matter in response to the draft decision.

New amendment proposed following draft decision

2408. In its revised proposal, Western Power has included a proposed new amendment to clause 21.3.[589]

> 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.
>
> 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.
>
> 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~~:
> >
> > ~~(a) effected in the joint names of the Parties; or~~
> >
> > ~~(b) Western Power must be endorsed on the policies referred to in Schedule 5 Part 1 and the User must be endorsed on the policies referred to in Schedule 5 Part 2,~~
> >
> > ~~for their respective rights and interests.~~

2409. Western Power's proposed changes to clause 21.3 are reasonable. The previous wording does not reflect normal commercial practice. In practice, Western Power is listed as an additional insured. The ERA agrees that the revised wording of clause 21.3 is reasonable and forms the basis of a commercially workable access contract, therefore meeting the requirements of section 5.3 and the Code objective.

[588] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24),* 11 December 2017, Issue 23.

[589] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 230-231.

APPLICATIONS AND QUEUING POLICY

Access Code requirements

2410. Section 5.1(g) of the *Electricity Networks Access Code 2004* (Access Code) requires that an access arrangement include an application and queuing policy, which is a policy that sets out the access application process.

2411. Sections 5.7 to 5.11 of the Access Code detail the specific requirements for an applications and queuing policy:

5.7 An applications and queuing policy must:

(a) to the extent reasonably practicable, accommodate the interests of the service provider and of users and applicants; and

(b) be sufficiently detailed to enable users and applicants to understand in advance how the applications and queuing policy will operate; and

(c) set out a reasonable timeline for the commencement, progressing and finalisation of access contract negotiations between the service provider and an applicant, and oblige the service provider and applicants to use reasonable endeavours to adhere to the timeline; and

(d) oblige the service provider, subject to any reasonable confidentiality requirements in respect of competing applications, to provide to an applicant all commercial and technical information reasonably requested by the applicant to enable the applicant to apply for, and engage in effective negotiation with the service provider regarding, the terms for an access contract for a covered service including:

(i) information in respect of the availability of covered services on the covered network; and

(ii) if there is any required work:

A. operational and technical details of the required work; and

B. commercial information regarding the likely cost of the required work;

and

(e) set out the procedure for determining the priority that an applicant has, as against another applicant, to obtain access to covered services, where the applicants' access applications are competing applications; and

(f) to the extent that contestable consumers are connected at exit points on the covered network, contain provisions dealing with the transfer of capacity associated with a contestable consumer from the user currently supplying the contestable consumer ("outgoing user") to another user or an applicant ("incoming user") which, to the extent that it is applicable, are consistent with and facilitate the operation of any customer transfer code; and

(g) establish arrangements to enable a user who is:

(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; and

(ii) a 'default supplier' under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations; and

(h) facilitate the operation of Part 9 of the Act, any enactment under Part 9 of the Act and the 'market rules' as defined in section 121(1) of the Act; and

(i) if applicable, contain provisions setting out how access applications (or other requests for access to the covered network) lodged before the start of the relevant access arrangement period are to be dealt with.

5.8 The paragraphs of section 5.7 do not limit each other.

5.9 Under section 5.7(e), the applications and queuing policy may:

(a) provide that if there are competing applications, then priority between the access applications is to be determined by reference to the time at which the access applications were lodged with the service provider, but if so the applications and queuing policy must:

(i) provide for departures from that principle where necessary to achieve the Code objective; and

(ii) contain provisions entitling an applicant, subject to compliance with any reasonable conditions, to:

A. current information regarding its position in the queue; and

B. information in reasonable detail regarding the aggregated capacity requirements sought in competing applications ahead of its access application in the queue; and

C. information in reasonable detail regarding the likely time at which the access application will be satisfied;

and

(b) oblige the service provider, if it is of the opinion that an access application relates to a particular project or development:

(i) which is the subject of an invitation to tender; and

(ii) in respect of which other access applications have been lodged with the service provider,

(“project applications”) to, treat the project applications, for the purposes of determining their priority, as if each of them had been lodged on the date that the service provider becomes aware that the invitation to tender was announced.

5.9A If:

(a) an access application (the “first application”) seeks modifications to a contract for services; and

(b) the modifications, if implemented, would not materially impede the service provider’s ability to provide a covered service sought in one or more other access applications (each an “other application”) compared with what the position would be if the modifications were not implemented,

then the first application is not, by reason only of seeking the modifications, a competing application with the other applications.

5.10 An applications and queuing policy may:

(a) be based in whole or in part upon the model applications and queuing policy, in which case, to the extent that it is based on the model applications and queuing policy, any matter which in the model applications and queuing policy is left to be completed in the access arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model applications and queuing policy; and

(ii) sections 5.7 to 5.9;

(iii) the Code objective; and

(b) be formulated without any reference to the model applications and queuing policy and is not required to reproduce, in whole or in part, the model applications and queuing policy.

5.11 The Authority:

(a) must determine that an applications and queuing policy is consistent with sections 5.7 to 5.9 and the Code objective to the extent that it reproduces without material omission or variation the model applications and queuing policy; and

(b) otherwise must have regard to the model applications and queuing policy in determining whether the applications and queuing policy is consistent with sections 5.7 to 5.9 and the Code objective.

Current access arrangement

2412. The current access arrangement includes the applications and queuing policy at Appendix A.

2413. Significant changes were made at the third access arrangement (AA3) review, including the creation of competing applications groups, where applicants are grouped behind common network constraints to assess and tailor joint network solutions to provide access to all applicants in the competing applications group – rather than the previous process that provided one-off, single applicant solutions.

2414. The current applications and queuing policy deals with the following matters:

- procedural requirements for an access application and access offer (Part A)
- procedural requirements specific to an electricity transfer application (Part B)
- procedural requirements for a connection application (Part C).

2415. The procedural requirements for a connection application include queuing rules (clause 24). The queuing rules apply where Western Power receives two or more applications where the service sought in one connection application may affect Western Power's ability to provide covered services that are sought in other connection applications.

2416. Under the current policy Western Power may:

- Manage competing applications by forming them into one or more competing applications groups and assessing a single set of works for shared assets required to meet some or all of the requirements of each competing applications group.
- Form all the competing applications into one competing applications group or two or more competing applications groups as it considers appropriate given the nature of the applications, including how the competing applications impede each other in respect of network constraints, the size of capacity sought in each of the competing applications and the current level of spare capacity.[590]

[590] Spare capacity is defined as the maximum rate at which electricity can be transported through that part of the network in accordance with good electricity industry practice to provide covered services sought by an applicant having regard to Western Power's contractual obligations in respect of the network.

2417. When determining whether there is spare capacity to provide covered services requested, Western Power must assume that any existing access contract will be renewed in accordance with the terms of that contract.

2418. Applicants may request Western Power to develop an applicant-specific solution, either at the time of application, or at any time after application. Such applicants can choose whether or not to also be included in a competing applications group.

Western Power's initial proposal

2419. Western Power considered the changes made to the applications and queuing policy for AA3 would lead to more efficient and less costly augmentation of the network over time. In its proposal for this fourth access arrangement (AA4), Western Power stated:

> The changes resulted in a significant improvement to how our customers connect to the network, and we plan to build on this through the proposed changes …

2420. Western Power proposed 31 amendments to the policy as well as some administrative changes that it considered would improve its application. Western Power noted the amendments had been developed in consultation with stakeholders and through its experience in implementing the policy during AA3.

2421. The proposed changes included:[591]

- Making spare capacity available to non-competing applications group members.
- Withdrawing dormant applications from access queues.
- Providing customers with more options for their connection applications when their circumstances change.
- Providing more clarity around the preliminary access offer process.
- Providing Western Power with the ability to terminate competing application groups when a network access solution is not viable, rather than the group existing in perpetuity.
- Ensuring consistency with the *Electricity Corporations (Prescribed Customers) Order 2007*. Western Power noted the following:

  > Currently the applications and queuing policy considers contestability on an exit point by exit point basis. Where the customer consumes (or is reasonably expected to consume) 50 MWh or more at an exit point, the customer is considered contestable. Where consumption is below 50 MWh, the customer is not contestable.
  >
  > Western Power has identified this is inconsistent with the Prescribed Customers Order, which considers the customer's portfolio of exit points.
  >
  > The Order provides that a customer is contestable where it has a portfolio of exit points (a hospital or university for example), and one or more of the exit points exceeds the 50 MWh threshold. Under the current AQP, the customer would only be considered contestable (and, therefore, able to purchase electricity from retailers other than Synergy) at the exit point that exceeds 50 MWh, but not at the other sub-50 MWh exit points.

[591] Western Power, *Access arrangement information,* 2 October 2017, pp. 261-267.

We propose to amend the AQP to align it with the Prescribed Customers Order."

- Clarifying the policy only applies to covered services.
- Clarifying what information provided by customers is confidential and what can be shared with third parties.
- Allowing provisions for both electricity transfer applicants and connection applicants to depart from the policy in progressing an application.

2422. The applications and queuing policy applies to all covered services, including reference and non-reference services.

2423. Most customers are on reference services, but the ERA was aware that Western Power had negotiated non-reference services with some customers, including constrained network connections.[592] As discussed earlier, negotiating non-reference services is permitted, and encouraged, under the Access Code.

2424. Prior to March 2016, in order to offer a constrained network connection Western Power had to apply to the ERA for an exemption from the Technical Rules. In November 2016 the ERA approved an amendment to Western Power's Technical Rules. As set out in the final decision[593] published in November 2016:

> Western Power proposed to amend the N-1 criterion[594] in the Technical Rules in order to allow voluntary load shedding and post contingent "run back" generation tripping for user agreed connections. This will allow Western Power, where it has an agreement with a user, to switch off some loads (and some generators), in response to network needs. Western Power considers this amendment will promote more efficient network operation.

2425. However, the Wholesale Electricity Market (WEM) design is based on an assumption that all generators have unconstrained connections[595] and, therefore, will be able to generate whenever called upon in normal operating conditions. System Management therefore does not have the necessary tools to physically manage significant numbers of constrained generators.

2426. There is also a risk the economic dispatch of energy in the wholesale market will be affected as constraints are not taken into account when developing the merit order.[596]

2427. Plans were being made to introduce a constrained network wholesale market design by July 2018. The State Government has indicated its intention to proceed with this plan but the implementation date is uncertain.

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[592] That is, under certain agreed circumstances the customer will curtail its load or generation.

[593] Economic Regulation Authority, *Western Power's Proposed Amendments to the Technical Rules Submitted March 2016 Final Decision*, November 2016, p. 12.

[594] Terminology such as "N" or "N-1" is commonly used for describing the level of security of the transmission system. Where loss of a single transmission element (a line, transformer or other essential piece of equipment) could cause a supply interruption to some customers, the level of security of supply is said to be "N" or "N-0". "N-1" is a higher level of security and describes a network built to a standard such that a network element can be out of service without overloading the remaining elements or resorting to load shedding.

[595] That is they will always be able to generate if they are selected in the merit order to be dispatched.

[596] The merit order is the ranking of generator pricing offers to the wholesale electricity market from lowest to highest with the cheapest generators being selected to generate.

2428. The difficulties this uncertainty causes for the current WEM design have restricted the number of constrained connections Western Power has been able to offer. Consequently, Western Power has developed an interim solution which will enable generators in some long-standing groups of competing applicants to connect on a constrained basis over the next year or so.

Submissions on Western Power's initial proposal

2429. Submissions from Alinta Energy (Alinta), the Australian Energy Council (AEC), Change Energy, Community Electricity, Emergent Energy, Mr Stephen Davidson, Perth Energy and Synergy addressed the applications and queuing policy. General views expressed in these submissions are provided below, with the details of specific matters addressed under "Considerations of the ERA".

2430. Emergent Energy considered the policy (and the competing applications group process in it) had been inadequate. It submitted:[597]

> Project proponents have often spent years and large amounts of money navigating the AQP process, often with no evident progression. A problem with the provision of services from a monopoly service provider is that there is no competition to benchmark against; and indeed, no competitive structure to require it to take risks in order to be chosen as the service provider.
>
> While the provision of connection services to customers is not a regulated part of the business, the quality of the services provided would be unlikely to be acceptable, and Western Power would have suffered significant customer leakage, in a truly competitive environment. As it stands, Western Power has received significant revenue through the provision of poor quality connection services. Whether this is performed on a cost-recovery basis or not is irrelevant.[598]

2431. Change Energy expressed similar views:[599]

> It has been Change Energy's experience that end-use customers find the process to trying to connect to the network both frustrating and costly. Initial quotes for connection can vary widely from actual costs. It should be noted that Western Power does not take any commercial risks when offering connections to customers and this should be considered when reviewing the rate of return calculations.

2432. Alinta provided general support for changes that would improve the policy and the ability for new generators to connect to the network in a timely and efficient manner.[600]

2433. The AEC considered the proposed changes to the policy did not necessarily balance the interests of the network operator and a retailer seeking a network connection. It submitted Western Power's proposal needed to be considered against the requirements of the Access Code (and the Access Code objective) as to:[601]

- Whether the policy applies to all services provided by Western Power under the Access Code or just covered services.

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597 Emergent Energy, *Western Power AA4 Discussion Paper, 8 December 2017*, Issue 3 (connection services).

598 Emergent Energy submission, p. 13.

599 Change Energy, *Change Energy's submission on AA4*, Issue 3.

600 Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 2.

601 Australian Energy Council, Proposed Revisions to Western Power's Network Access Arrangement, 11 December 2017, pp. 4-5.

- How confidential information is treated.
- Whether dormant applications are dealt with in a legitimate, transparent and consistent manner.
- Whether there is a mandatory preliminary connection assessment in all instances.
- What constitutes a modification to equipment and facilities; for example, embedded generation and behind the meter energy efficient appliances.
- Whether there is sufficient clarity on the concept of “multiple trading” relationships.

2434. Perth Energy broadly supported Western Power’s proposed changes and provided specific support for the proposed amendments to allow multiple trading relationships at a connection point, clarify the “contestable” definition and remove dormant applications. It raised a concern with an existing requirement for the provision of information on the facilities and equipment seeking connection (clause 3.7(e) of the policy), which is discussed below.

2435. Alinta and Change Energy both noted that Western Australia’s current Wholesale Electricity Market design restricts Western Power’s ability to connect new generation:

> Western Australia is an attractive market for renewables investment given the availability of natural resources and the design characteristics. The current Wholesale Electricity Market arrangements are premised on an unconstrained network access design[602]. This has restricted Western Power’s ability to connect any large scale new entrant generators to its network because of the cost and timeframes associated with reinforcing its network under the unconstrained access model. As a consequence there has been limited investment in any generation in the SWIS in recent years.[603]

> Change Energy understands that there are many issues for generators trying to connect to the network, many of which are a result of the unconstrained access required under the Market Rules.[604]

2436. Alinta further expressed support for the generator interim access solution to enable Western Power to connect customers on a constrained basis under the current electricity market:

> … to allow new generators to connect to the network immediately on a constrained basis, during 2017 the Western Australian Government, the Australian Energy Market Operator (AEMO), Western Power and the Public Utilities Office (PUO) worked with the industry to develop the Generator Interim Access (GIA) solution (including the requisite amendments to the Reserve Capacity Mechanism (RCM) rules to allow certification on a constrained basis). The GIA solution will facilitate network connections before the implementation of a fully constrained network access model, without impacting on the rights of existing generators currently connected on an “unconstrained” basis”.

> This industry leadership, including the development of the GIA solution and amendments to the RCM, was required to urgently facilitate the changes necessary to

[602] The market design assumes that electricity flows from generators to loads are unrestricted, with each generator able to output to its maximum capacity without threatening system security under normal network operating circumstances (i.e. with no major transmission lines out of service).

[603] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 2.

[604] Change Energy, *Submission on AA4*, 11 December 2017, issue 3.

> ensure renewable investment continued to occur in the South West of Western Australia, which will in turn assist with the State's ability to meet its national Renewable Energy Target obligations in coming years.

2437. Community Electricity was also supportive of the development of the generator interim access solution:[605]

> We congratulate Western Power on the cultural adjustment that underpins its Generator Interim Access regime and its industry leadership in one of the most important energy opportunities of recent time – capturing the benefits of the Clean Energy Regulations.

2438. Although Change Energy supported moving to a constrained access model and co-optimised dispatch run by the market operator. It did not support:[606]

> …connection arrangements that result in un-economic, inefficient dispatch of generators in order to satisfy Western Power's obligation to connect.

Considerations of the ERA

2439. The ERA is required to assess the proposed revisions to the applications and queuing policy against the requirements of sections 5.7 to 5.11 of the Access Code.

2440. The ERA's considerations are set out in the following order:

- Western Power's process to develop its proposed amendments
- Western Power's proposed amendments
- Suppliers of last resort and default suppliers
- Facilitation of Part 9 of the *Electricity Industry Act 2004*
- Other matters raised in submissions.

Western Power's process to develop amendments

2441. Western Power's process for developing its initial proposed amendments was guided by a two-stage customer consultation process. The first stage was managed by its consultant (GHD) and involved the following steps:

- Assessment of required changes
  - GHD assessed, reviewed, and confirmed with Western Power the required changes to the applications and queuing policy. It documented these changes and produced a briefing paper to guide and inform stakeholders on the proposed changes and the consultation process.
  - Twenty changes were proposed. Detailed drafting of the proposed amendments was not included with the briefing paper.
- Stakeholder engagement
  - A stakeholder forum was held on 3 May 2017. Attendees were provided with the briefing paper before the forum and were given the opportunity to provide input to the review process at the structured forum.

[605] Community Electricity, *Response to ERA Public Consultation*, p. 1, paragraph 3.

[606] Change Energy, *Change Energy's submission on AA4*, Issue 3.

- One-on-one interviews were held in person and by telephone to extend the reach to stakeholders in more remote regions of the network geography.
- Written submissions were invited from stakeholders.
- Verbal feedback was received from Lacour Energy and written feedback was received from Perth Energy and Synergy.

2442. GHD prepared a written report, which detailed stakeholder feedback from the above process.[607] Western Power did not provide GHD's report to stakeholders for review. GHD's recommendations included:

- Specific consideration should be given to the requests for additional clarity raised in the Synergy submission.
- Detailed drafting of proposed changes should be made available to stakeholders.
- Information should be provided that details how the applications and queuing policy will interact with applicants wishing to establish a constrained access offer enabled by the generator interim access solution. Western Power should consider whether any revisions are required to the policy to provide this clarity.

  It appears that elements of the AQP will apply as new connection points will need to be established but it is probably the case that these connections are viewed as not competing and therefore many of the provisions in the AQP may not be triggered. Creating a process flow diagram that demonstrates the path through the AQP process that a GIA enabled connection is expected to take, may add significant value for connection applicants and clarify the need for change to the AQP.

2443. Western Power then prepared an amended applications and queuing policy that took into account stakeholder feedback. Two of the original proposed amendments were deleted[608] and eight new amendments[609] were included. Western Power provided the draft policy, together with a summary of changes, to stakeholders for further comment. Three submissions were received.

2444. Western Power's final proposal, submitted to the ERA on 2 October 2017, included five new amendments[610] making 31 proposed substantive amendments in total. Western Power also included 12 amendments which it described as minor administrative amendments.

2445. Attachment 12.3 to the access arrangement information summarised the changes made by Western Power in response to the stakeholder consultation or, where applicable, gave reasons why comments made by the stakeholders had not been incorporated into the revised applications and queuing policy.

2446. While Western Power had demonstrated how it dealt with stakeholder comments in Attachment 12.3, some submissions to the ERA claimed that Western Power did not adequately address some comments that were made. Specific concerns identified in submissions received by the ERA are addressed below.

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[607] GHD Advisory, *Western Power AQP Review Report [confidential]*, 12 June 2017.

[608] Items (ID) 3 and 17.

[609] Items (ID) 8A, 15A, 21, 22, 23, 23A, 23B and 24.

[610] Proposed amendments to support "Time of use" tariffs and advanced metering (ID 27 to 31).

2447. The ERA considered that Western Power undertook an adequate consultation process with interested parties. However, the process would have been more transparent if the report prepared by GHD that summarised stakeholder feedback had been included with the draft amended applications and queuing policy circulated by Western Power to stakeholders in August 2017.

Western Power's proposed amendments

2448. Attachment 12.3 to the access arrangement information sets out Western Power's proposed amendments to the applications and queuing policy. The ERA considered each of the proposed amendments in turn below, with the "change identification numbers" (or ID numbers) used in Attachment 12.3 reproduced for reference purposes.

2449. Where relevant, feedback from Western Power's stakeholder engagement and the ERA's public consultation, was considered.

Proposed amendments to connection application provisions

Spare capacity (ID 1)

2450. The current applications and queuing policy only supports capacity being provided to members of a Competing Applications Group (CAG) where that capacity has been developed by shared works for the group. Occasionally, spare capacity becomes available without any customer funded shared works, for example, through growth driven network augmentation or through a reduction in existing contracted load/generation capacity. As the formation of a CAG relies on the identification of shared works, the CAG mechanism cannot be used to release this capacity to CAG members.

2451. Feedback from Western Power's stakeholder engagement indicated general support for a process that allows spare capacity to be allocated. There were divided views on whether the spare capacity should be allocated based on priority date or those most ready to proceed. Stakeholders also sought clarity on whether capacity would be distributed across all connection applicants or only CAG members.[611]

2452. Taking account of stakeholder feedback, Western Power proposed to introduce a new clause (24.8(b)) to enable spare capacity that becomes available other than by shared works to be offered to applicants on a priority date (i.e. first come, first served) basis until no spare capacity remains.[612] Capacity that becomes available may be offered to applicants who are members of a CAG, or to other applicants who are not members of such a group:

> (b) If, at any time, spare capacity to provide covered services becomes available without the need for any works for shared assets and there are applicants who are competing for such spare capacity, Western Power may allocate that spare capacity to applicants on the basis of priority date until no spare capacity remains without forming a competing applications group. To avoid doubt, the spare capacity may be offered to an applicant who is

[611] Western Power, *Access arrangement information: Attachment 12.2: GHD AQP Customer Engagement Report [confidential],* 2 October 2017, section 4, table 4.1 (ID 1).

[612] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 3.

part of a competing applications group and an applicant who is not part of a competing applications group.

2453. The following consequential amendment was made to clause 24.1(a) to confirm that Western Power's obligation to form a CAG is subject to (proposed) clause 24.8(b):

> 24.1 Formation of Competing Applications Groups
>
> (a) Where Western Power assesses that an application is competing with other applications then Western Power will, subject to clauses 16.5, and 24.8(b), manage competing applications by forming them into one or more competing applications groups and assessing a single set of works for shared assets required to meet some or all of the requirements of each competing applications group. To avoid doubt…

2454. No submissions on Western Power's initial proposal addressed Western Power's proposal to insert new clause 24.8(b) and make a consequential amendment to clause 24.1.

2455. In the draft decision the ERA agreed it is in the interests of both applicants and Western Power to make spare capacity available in situations where there is no need for shared works. Western Power's proposed amendment allowed this to occur and for this reason it was considered to be consistent with the requirements of the Access Code.

2456. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

Dormant applications (ID 2)

2457. Western Power was concerned that applicants could remain in the process indefinitely, in some cases having had no contact with Western Power for many years. It considered this affected the release of capacity to applicants who were ready, willing and able to proceed, but had a later priority date. It also affected the objections process because Western Power was obliged to provide all competing applicants with an opportunity to object to an applicant-specific solution.

2458. The following feedback was reported from Western Power's stakeholder engagement:[613]

- It is important to tidy up the list.
- There should be a mechanism that allows an applicant to stay in the process.
- If there are several applications, there should be a mechanism to determine which are viable.
- Financial commitment should be demonstrated to avoid dormancy.
- Criteria should include the applicant's intent to progress the project.

2459. Western Power proposed to introduce a new clause (22) that detailed the process and criteria to determine whether an application is *dormant*, and whether such an application should be progressed or withdrawn:

[613] Western Power, *Access arrangement information: Attachment 12.2: GHD AQP Customer Engagement Report [confidential],* 2 October 2017, section 4, table 4.1 (ID 2).

22 Dormant applications

(a) Subject to clause 22(b), Western Power may 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) 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) 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.

2460. Consequential amendments from the introduction of clause 22 included a new defined term (dormant application) added to clause 2.1 and drafting changes to clause 3.14:

2.1 Definitions

…

"dormant application" means a connection application in respect of which:

(a) no work has been undertaken by Western Power; or

(b) no work has been agreed by Western Power and the applicant to be undertaken by Western Power,

to progress the application, including a system or other study, the preparation of a detailed cost estimate or other work, under clauses 20.2, 20.3 or 24, for a period of 12 continuous months calculated retrospectively from the date that the assessment as to dormancy is made.

3.14 Applications Do Not Expire

~~An~~Unless expressly provided otherwise by this applications and queuing policy, an application does not expire due to the passage of time.

2461. Synergy's submission to the ERA on Western Power's initial proposal agreed in principle with introducing a process for withdrawing dormant applications. However, to be consistent with the requirements of the Access Code (section 5.7), Synergy considered further amendments were needed. It submitted that Western Power's proposal was to:[614]

- Adopt the 3 year time line in the model applications and queuing policy (Appendix 2 to the Access Code). The definition of "dormant application" in the model applications and queuing policy refers to an "application that was lodged by the applicant on a date that is more than 3 years before the date the service provider is considering the application..." Section 5.11(b) of the Access Code requires the Authority to have regard to the model applications and queuing policy in determining whether the AQP is consistent with sections 5.7 to 5.9 and the Access Code objective. The model applications and queuing policy has been determined by the Authority as meeting the requirements of the Access Code. Adopting a 3 year time line in the AQP is then consistent with section 5.7 of the Access Code.
- Be subject to WP meeting its obligations under the AQP (including acting reasonably, expeditiously, diligently and in good faith in relation to the proposed access contract, as required by clauses 3.1 and 3.12). This is consistent with section 5.7(b) of the Access Code (as well as sections 2.8(a) and 2.8(b) of the Access Code).
- Not allow deemed withdrawal where delay is beyond the reasonable control of the applicant. Such a condition is consistent with section 5.7(c) of the Access Code, which requires an AQP to set out a reasonable timeline for progressing access contract negotiations and oblige applicants (and the service provider) to use reasonable endeavours to adhere to the timeline.
- Ensure a notice under clause 22(a) is mandatory, not discretionary. Mandating a notice to be issued in all circumstances will allow users and applicants to understand in advance how the AQP will operate – this ensures consistency with section 5.7(b) of the Access Code. Further, mandating a notice to be issued is consistent with clause A2.78 of the model applications and queuing policy (which, as noted at dot point one above, is a policy which the Authority has determined meets the requirements of the Access Code).
- Ensure clause 22(d)(ii) also has "12 months" amended to "3 years". As noted at dot point one above, adopting a 3 year time line is consistent with the model applications and queuing policy and therefore consistent with section 5.7 of the Access Code.
- [Remove] the words "upon Western Power's receipt of that response" from clause 22(d) – the inclusion of these words in this subclause does not make sense.

2462. Alinta's submission to the ERA supported Western Power's proposal for dormant applications. It considered:[615]

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[614] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, pp. 15-16, paragraphs 59.1 to 59.5 and 60.

[615] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 3.1.

> … inactive applications impact the priority date mechanism and the release of spare capacity to applicants ready, willing and able to proceed to a connection but whose applications have a later priority date.
>
> In noting this support, Alinta urges consideration of whether a 12 month plus 12 month dormant application process is too long, and whether a shorter period would better meet the Access Code objectives.

2463. Perth Energy's submission to the ERA also supported the proposal to remove dormant application:[616]

> …this will facilitate competition if the amount of unused capacity can be maximised and made available to the market for investment in. Perth Energy also notes, that the notion of dormant applications should be extended to sites that have contracted capacity but have either been shut or not used for a period of time. Holding onto unused network access should be actively discouraged as it is an effective way to stifle competition upstream of the network and would be in direct contravention of the access code objectives.

2464. In the draft decision, the ERA noted the need to remove dormant applications from the queue suggested that the changes made to the applications and queuing policy during AA3 may not have been working as effectively as hoped. When proposing its changes to the policy for AA3, Western Power noted the changes would enable applicants to determine how they progressed through the process. Western Power considered the proposed changes may have lessened the need for a queue:[617]

> Applicants determine how they progress through the process through explicit decision stages where they lodge applications, initiate planning studies, accept/decline preliminary offers and decide whether to accept the final access offers that [Western Power] make to them. Beyond these decisions the process is largely mechanical, which removes our need to exercise discretion by classifying customer applications as dormant or initiating bypass of applications to promote other applicants in the queue."
>
> At present there is a single queue where applicants remain in the order they arrive, regardless of their readiness to proceed to connection. Instead … the applicants that are commercially ready with viable projects determine their own willingness to proceed, or alternatively withdraw from the process as they approach decision stages and the payment of associated fees.

2465. However, the proposal to introduce a process for dormant applications appeared to be beneficial and supported by stakeholders.

2466. The ERA agreed with some of the suggested amendments raised by Synergy in its submission. Subject to the following amendments, the ERA considered Western Power's proposal to insert a new clause (22) for dormant applications, and to make other consequential amendments, was consistent with the requirements of the Access Code:

- The time period in the proposed definition of "dormant application" and clause 22(e)(ii) was to be changed to three years to be consistent with the model applications and queuing policy in the Access Code. The ERA had not received any information to suggest that a shorter length of time would be more appropriate and warrant a departure from the model policy.

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[616] Perth Energy, *Submission the ERA regarding Western Power's proposed revisions to the access arrangement for the Western Power network*, November 2017, p. 12.

[617] Western Power, Access arrangement information for 1 July 2012 to 30 June 2017, pp. 325-326.

- Clause 22(a) was to be changed to require that Western Power "must" rather than "may" give an applicant written notice in respect of dormant applications. This amendment was consistent with clause 5.7(b) of the Access Code as it provided clarity about how the policy will operate in respect of dormant applications.
- Clause 22(b) was to be changed to require Western Power to "not issue a notice if the failure... is due to a material breach by Western Power of the applications and queuing policy or due to Western Power's negligence or wilful default." This amendment made clause 22 subject to compliance with clauses 3.1 and 3.12 of the policy and where the delay is beyond the reasonable control of the applicant due to Western Power's actions.
- Clause 22(d) was to remove the words "upon Western Power's receipt of that response" because the inclusion of these words do not make sense.

2467. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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 [paragraph 2466 above].

2468. In its revised proposal, Western Power states it has accepted draft decision required amendment 62 in principle with modifications.[618]

> 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. 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.
>
> …
>
> 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.
>
> 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.
>
> 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

[618] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 232-236.

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.

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.

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.

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) …

(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.~~

2469. The intention of the ERA’s draft decision was that Western Power should not be able to deem applications less than three years old to be dormant (for consistency with the model applications and queuing policy), or for an application to become dormant due to Western Power not progressing the application. It is also important that applicants have adequate opportunity to advise they do not wish to be deemed dormant before Western Power takes such action.

2470. The ERA accepts Western Power's proposed amendment to clause 22(a) to change "must" to "will" meets the intention of draft decision required amendment 62. The ERA also considers Western Power's proposed amendments to clause 22(d) satisfy the intention of draft decision required amendment 62.

2471. However, amendments are still required to ensure applications less than three years old cannot be deemed dormant (unless the applicant wants to withdraw it) or where lack of progress is due to Western Power not progressing the application.

Required Amendment 52

The provisions for dormant applications must be amended to ensure applications cannot be deemed dormant if they are less than three years old or the lack of progress is due to Western Power not progressing the application.

Options for responding to preliminary access offers (ID 4)

2472. Under the current applications and queuing policy, if a member of a CAG does not want to accept a notice of intention to prepare a preliminary access offer or a preliminary access offer, it must either progress its application as an applicant-specific solution, or have its application taken to be withdrawn.

2473. Western Power proposed to add a new clause (24.3(c)) to provide members of a CAG another option for responding to a notice of intention. The proposed new clause allowed members to opt out of the CAG and remain eligible for inclusion into another CAG while maintaining the priority date of its application. Western Power submitted that "exercising this option is similar in effect to providing written notice to [it] under clause 24.1(b2) prior to the issue of the notice of intention":[619]

> 24.3 Response to Notice of Intention to Prepare a Preliminary Access Offer
>
> Applicants must respond to the notice issued under clause 24.2 within 30 business days by:
>
> …
>
> (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 be considered for inclusion in another competing applications group in accordance with clause 24.1(a); or

2474. Synergy submitted that the use of the word "may" (between the words "and" and "be considered") in proposed clause 24.3(c) was discretionary – there was no obligation

[619] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 5.
Clause 24.1(b2) states: *"Where Western Power notifies an applicant under clause 24.1(b1) that the application has been sorted into one or more competing applications groups, then the applicant may choose by notice to Western Power at any time that it does not wish to be considered in one or more of the competing applications groups. Western Power will accept the choice of the applicant."*

on Western Power to consider the application for inclusion in another CAG. Synergy considered that the word “may” should be changed to “will” in this instance. Using the word "will" would provide clarity on how such a right to terminate CAGs would be practically implemented, and is consistent with sections 5.7(b) and 5.7(e) of the Access Code.[620]

2475. The ERA agreed with Synergy that use of the word “may” in the proposed clause 24.3(c) implied that the decision to consider the application for inclusion in another CAG in accordance with clause 24.1(a) was discretionary. If the intention of the proposed new clause is to promote fair market conduct by allowing an applicant to opt out of one CAG in order to be considered for another CAG at a later date, changing the word “may” to “will” gives effect and clarity to this intention.

2476. The ERA’s draft decision required the following amendment to Western Power’s proposal.

Draft Decision 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 2475 of this draft decision [paragraph 2475 above].

2477. In its revised proposal, Western Power has accepted draft decision required amendment 63 and has made the required amendment to clause 24.3(c).[621]

2478. No submissions were received on the draft decision.

2479. The ERA is satisfied that draft decision amendment 63 has been complied with.

2480. Western Power proposed to insert a further two new sub-clauses – (B) and (C) – under existing clause 24.5(a)(ii) to provide an equivalent option for members of a CAG to respond to a preliminary access offer:

24.5 Response to Preliminary Access Offer

(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:

(i) …

(ii) that it would reject such a preliminary access offer if it were an access offer and would request an amendment to the preliminary access offer. In this case Western Power and the applicant must negotiate in good faith regarding the form of the preliminary access offer, but if Western Power and the applicant have not agreed on the form of the preliminary access offer within 30 business days of the date on which the applicant received the preliminary access offer, then the ~~applicant will, unless it notifies Western Power that it wishes its connection~~ application and any associated electricity transfer application ~~to~~will be ~~taken~~deemed to ~~be~~have been withdrawn~~,~~ unless:

620 Synergy, *AA4 Submission Number 3: Western Power’s proposed application and queuing policy*, 8 December 2017, p. 24, paragraphs 111 and 112.

621 Western Power, Revised AA4 proposal: Response to the ERA’s draft decision, 14 June 2018, p. 236.

(A) <u>the applicant has notified Western Power in writing that it wishes to </u>be treated as having made an application for an applicant-specific solution … or

(B) <u>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 be considered for inclusion in another competing applications group in accordance with clause 24.1(a); or</u>

(C) <u>the failure to agree on the form of the preliminary access offer within 30 business days is due to Western Power acting in bad faith, in which case Western Power and the applicant must negotiate in good faith for a further period of 30 business days regarding the form of the preliminary access offer and clauses 24.5(a)(ii)(A) and 24.5(a)(ii)(B) shall apply. If no agreement is reached between Western Power and the applicant during this further period, and the applicant has not notified Western Power in accordance with clauses 24.5(a)(ii)(A) and 24.5(a)(ii)(B), the application and any associated electricity transfer application will be deemed to have been withdrawn; or</u>

(iii) that it would not accept such a preliminary access offer if ...

2481. Synergy submitted that the effect of the drafting in proposed clause 24.5(a)(ii)(C) was to have a protracted period over which negotiations were to be held if Western Power had acted in bad faith within the first 30 business days. Synergy did not consider this was consistent with Western Power's obligations to act expeditiously and diligently (both under section 2.8(a) of the Access Code, and under clause 3.12 of the policy). Given Western Power's obligations to act expeditiously and diligently, Synergy requested there also be a deemed withdrawal if Western Power failed to act expeditiously and diligently in agreeing the form of the preliminary access offer.[622]

2482. The ERA considered the proposed clause 24.5(a)(ii)(C) was acceptable because it was consistent with section 5.7(a) of the Access Code. It was in the interests of applicants to allow their access offers to remain active despite any delay due to bad faith on Western Power's behalf. If an applicant no longer wishes to continue to negotiate with Western Power it can withdraw its application under clause 3.13 of the policy.

2483. Western Power's proposed amendments to clause 24.5, including new clauses 24.5(a)(ii)(B) and (C) were accepted subject to the following amendments:

- The word "after" was to be reinstated in clause 24.5(a) to clarify that the 30 business days commence the day *after* the receipt of the notice. The proposed change (to replace the word "after" with "of") removed this clarity. Similarly, the following drafting amendments was to be made to clause 24.5(a)(ii) to improve clarity:

[622] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 24, paragraphs 113 and 114.

(ii) … within 30 business days from~~of~~ the date on which the applicant received the preliminary access offer, then the application and …

- Consistent with the ERA's considerations for clause 24.3(c), the word "may" was to be amended to "will" in clause 24.5(a)(ii)(B) as follows:

(B) … the application shall retain its priority date and ~~may~~will be considered for inclusion in another competing applications group …

2484. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 2483 of this draft decision [paragraph 2483 above] to:

- clarify that the 30 business days commence after the receipt of the notice (clause 24.5(a)(ii)); and
- replace the word "may" with "will" (clause 24.5(a)(ii)(B)).

2485. In its revised proposal, Western Power has accepted required amendment 64 and has made the required amendments to clause 24.5.[623]

2486. No submissions were received on the draft decision.

2487. The ERA is satisfied that Western Power has complied with draft decision amendment 64.

Funding studies to prepare a notice of intention (ID 5)

2488. The current applications and queuing policy does not contain any mechanism for funding studies required to prepare a notice of intention. Western Power considered studies may be required to provide a reasonable level of information to CAG members so they can make an informed decision about accepting a notice of intention and funding the subsequent solution.

2489. The following feedback was reported from Western Power's stakeholder engagement:[624]

- The mechanism should only be triggered in the event that Western Power incurs a material amount of additional cost in completing the steps required to prepare the notice of intention.
- Fees should be presented in advance to the members of the CAG.

2490. Western Power proposed to insert a new clause (24.1(d)) to confirm that where it considers studies are necessary to prepare a notice of intention, Western Power could issue a processing proposal to the members of a CAG in accordance with clause 20.2 (which covers the processing of a proposal):

(d) To avoid doubt, where Western Power considers that to issue a notice of intention to prepare a preliminary access offer it must perform any system or other studies, Western Power may provide a processing proposal to the

[623] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 237.

[624] Western Power, *Access arrangement information: Attachment 12.2: GHD AQP Customer Engagement Report [confidential],* 2 October 2017, section 4, table 4.1 (ID 5).

applicants within the competing applications group in accordance with clause 20.2.

2491. A consequential amendment was made to clause 20.1(a)(ii) to include a reference to (proposed) new clause 24.1(d). The amendment confirmed that an applicant must fund studies under that clause, which it has agreed to Western Power performing.

2492. Synergy submitted that Western Power's proposed new clause 24.1(d) was to be made subject to the timeline under clause 24.1(b1) to be consistent with the requirements of the Access Code (section 5.7(b)).[625]

> That is, the study proposal and costs must be provided to the applicant, within 30 business days of the application and at the same time they are notified of their CAG. Such a provision would also be consistent with section 5.7(d) of the Access Code (which section obliges the service provider to provide an applicant all commercial information reasonably requested by the applicant to enable the applicant to apply for, and engage in effective negotiation with the service provider).

2493. The ERA considered Western Power's proposal and Synergy's submission and was of the view that the proposal was consistent with sections 5.7(b) and (c) of the Access Code – the clause:

- Was sufficiently detailed to enable users and applicants to understand (in advance) how the applications and queuing policy would operate.
- Set out a reasonable timeline for the commencement, progressing and finalisation of contract negotiations between Western Power and the applicant, with an obligation to use reasonable endeavours to adhere to the timeline.

2494. Synergy's concern appeared to be that the proposed new clause deprived applicants of the ability to apply and engage in effective negotiations with Western Power, which was not the case. If Western Power considered other studies were required it was to follow the process in clause 20.2 of the policy – clause 20.2(a) requires Western Power to provide notice to the applicant of timing and cost estimates for the studies. This gives the applicant sufficient information to decide whether to withdraw its application, or seek to apply for an applicant-specific solution.

2495. However, the ERA considered the drafting of clause 20.2(a) could be improved to make explicit the obligation for Western Power to expeditiously provide proposals to applicants consistent with clauses 3.1 and 3.12 of the policy. The ERA required clause 20.2(a)(i) to be amended as follows:

> (i) Western Power must provide a proposal within a reasonable time to the applicant outlining the scope, timing and a good faith estimate …

2496. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 …"

[625] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 23, paragraph 102.

2497. In its revised proposal, Western Power has not accepted draft decision required amendment 65. Western Power submits: [626]

> 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.
>
> 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.

2498. Having considered Western Power's submission regarding required amendment 65 as set out in paragraph 2497, particularly the requirement act reasonably and to process applications expeditiously and diligently under clauses 3.1 and 3.12 of the applications and queuing policy and under the Access Code, the ERA agrees that it is unnecessary to require the additional obligation in clause 20.2(a)(i). The proposed clause 20.2(a)(i) of the applications and queuing policy meets the Access Code requirements and the ERA no longer requires draft decision required amendment 65.

Forecast natural load growth considerations (ID 6)

2499. Western Power considered that it was able, acting in accordance with good electricity industry practice and the Code objective, to take into account matters such as forecast natural load growth to determine available spare capacity and undertake network planning.

2500. Western Power proposed to change clause 3.15(d) of the applications and queuing policy to make clear that forecast natural load growth is a relevant consideration in undertaking network planning:

> 3.15 Network Planning
>
> …
>
> (d) In undertaking network planning Western Power 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.

2501. Similar wording changes were proposed to clause 24.8(a) and the definition of "spare capacity" as follows:

[626] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 238.

24.8 Spare Capacity

(a) In determining whether there is spare capacity to provide covered services requested in a connection application or group of applications, Western Power 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.

2.1 Definitions

…

"spare capacity" means the capacity, from time to time, of the network, as configured at the time of an application, to provide the covered services sought in the application, having regard to matters including Western Power's contractual obligations in respect of the network and forecast natural load growth.

2502. While Synergy considered forecast natural load growth was fundamental to determining any required work in relation to spare capacity, it submitted Western Power's proposed amendments to address this matter were ambiguous – there was ambiguity about how spare capacity was determined, and which amounts were subject to required work funded by a contribution and which amounts were not.

2503. Synergy submitted that it was essential for users to be given greater clarity, with the following points needing to be addressed in the applications and queuing policy:[627]

"Forecast natural load growth" should be defined in the AQP.

It should be specified how "forecast natural load growth" is to be determined, including, among other things:

- whose forecast(s) WP should have regard to, for example whether it is required to consider forecasts proposed by AEMO or to prepare its own natural load growth forecasts;
- the extent to which the interests of customers, users and network operator are to be balanced (as contemplated under section 5.7(a) of the Access Code);
- there must be reasonable grounds published supporting any forecast;
- WP must clarify how, given it proposes all connection points will become bidirectional points, increased distributed generation is dealt with in the concept of "forecast natural load growth" and whether capital investment in networks to facilitate distributed generation will be encouraged and if so how; and
- clarity should be provided on whether WP considers "forecast growth" includes negative growth.

2504. Synergy also submitted that it did not agree with the proposed definition of "spare capacity" and that certain matters should be expressly stated in the policy:[628]

Synergy does not agree with the proposal to include the words "matters including" in the definition of "spare capacity". These words broaden, without providing any clarity, the scope of what WP may have regard to in determining "spare capacity" and are therefore ambiguous and inconsistent with the Access Code and section 5.7(b) of the Access Code.

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[627] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 17, paragraph 66.

[628] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, pp. 17-18, paragraphs 67 and 68.

For consistency with the Access Code, Synergy recommends clarifying expressly:

- no part of a user's "contracted capacity" (whether utilised or unutilised) can be treated as "spare capacity" (unless otherwise expressly agreed by the user).

So, for example, it needs to be clarified that a "reduction" in contracted capacity (as contemplated in clause 23 of the AQP) does not include unutilised capacity in respect of a user's contracted capacity and that spare capacity does not "become available" (as contemplated in clause 24.8(b) of the AQP simply because contracted capacity is not utilised.

This clarification could be provided in the definition of "contracted capacity" and is consistent with the existing definition of "spare capacity" …

- determining spare capacity in no way limits WP's obligation under section 2.10 of the Access Code to undertake and fund any required work.

2505. The ERA considered that Western Power's proposed amendments to clause 3.15(d), clause 24.8(a) and the definition of "spare capacity" were unnecessary and contrary to the requirements of the Access Code for the following reasons:

- While forecast natural load growth should be taken into account in network planning, the purpose of clause 3.15(d) in the applications and queuing policy is to explain how applications received under the policy will be taken into account in Western Power's network planning – it is not intended to explain more generally how network planning is actually undertaken.
- The existing definition of "spare capacity" in the policy is the same as the definition in the model applications and queuing policy under the Access Code.
- The ERA was concerned the proposed amendment to the definition of spare capacity could result in Western Power leaving existing capacity unutilised on the basis that it may one day be required, which is inconsistent with the objectives of the Access Code.

2506. The ERA considered the existing requirement to have regard to existing contractual obligations was sufficient to ensure it did not allocate capacity through the applications and queuing policy that is needed by existing users. Additional capacity required to meet natural load growth in the longer term was to be included, as it presumably already is, in Western Power's network planning.

2507. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

2508. In its revised proposal, Western Power has not accepted draft decision required amendment 66. Western Power submits:[629]

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.

[629] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 238-240.

> 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.
>
> 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. 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.
>
> 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.
>
> 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.
>
> 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.
>
> 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.
>
> 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.

2509. As set out in the draft decision, the current requirements in the applications and queuing policy to have regard to existing contractual obligations are sufficient to ensure Western Power does not allocate capacity through the applications and queuing policy that is needed by existing users. Specific applications for capacity and other forecast load increases (including possible applications for subdivisions) can all be taken into account in network planning.

2510. Western Power's proposed amendments to clauses 3.15(d) and 24.8(a) and the "spare capacity" definition are unnecessary and contrary to the requirements of the Access Code.

Required Amendment 53

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.

Tender projects (ID 7)

2511. Existing clause 24A.2 of the applications and queuing policy covers provisions for tender projects (for instance, where two or more applicants are competing under a tender process) and allows a successful tenderer to be given the same priority date as the unsuccessful tenderer with the earliest priority date. Western Power submitted that this approach is inconsistent with, and difficult to implement in, the CAG regime.[630] The approach can also create inequities because it can result in a successful tenderer with a later priority date receiving access ahead of applicants who lodged their application before the successful tenderer. Western Power indicated that it wanted to avoid giving preference to an applicant who is successful in a tender process over other applicants.

2512. Western Power proposed to delete clause 24A.2 from the policy. Related and consequential amendments include the deletion of:

- The term "project" from clause 2.1.
- Clause 3.7(a), which requires the applicant to provide information on whether its connection application is connected with a tender process.

2513. No submissions to the ERA addressed Western Power's proposal to delete existing clause 24A.2 from the policy.

2514. Section 5.9(b) of the Access Code deals with, but does not require, the applications and queuing policy to provide for tender applications. Western Power's proposal to delete existing clause 24.A2 from the policy was therefore not contrary to the requirements of the Access Code.

2515. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

[630] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 7.

Objections to applicant-specific solutions (ID 8)

2516. Western Power submitted that the current applications and queuing policy does not require it to give notice of an applicant-specific solution to all applicants who may be impeded by the application-specific solution.[631] Western Power is only obliged to notify competing applicants that were in the same CAG and existing users who may be impeded by the applicant-specific solution. The notification gives applicants an opportunity to object to the applicant-specific solution being considered.

2517. However, under clause 16.5, an applicant may elect for its application to be processed as an applicant-specific solution before being grouped in a CAG. Western Power submitted that this can create technical problems and inequities where applicants who may be impeded by the applicant-specific solution do not have a right to object:[632]

> For equity and transparency purposes, all applicants who may be impeded by an applicant-specific solution should have the right to object to that solution being provided. However, in order to ensure that the applicant who has funded works to develop an applicant-specific solution is not unfairly subjected to potential objections from competing applicants with later priority dates, only competing applicants with earlier priority dates are proposed to be given the opportunity to object to the proposed applicant-specific solution.

2518. Western Power proposed to amend clause 20.3(b)(ii) to replace the words "that was within the same competing applications group" with the words "with an earlier priority date". This change required Western Power to provide any competing applicant that has an earlier priority date with an opportunity to object to an applicant-specific solution after the relevant study is completed. The proposed change and consequential amendments to clauses 20.3(c), (d) and (e) are set out below:

> 20.3 Applicant-specific Solution Option
>
> (a) An applicant may request Western Power to perform a study of the nature and costs of an applicant-specific solution to satisfy the connection application...
>
> (b) Once Western Power has completed the study, it must provide:
>
> (i) existing users that Western Power considers may be impeded; and
>
> (ii) any competing applicant ~~that was within the same competing applications group as the applicant~~with an earlier priority date,
>
> with the opportunity to object to providing the applicant-specific solution to the applicant.
>
> (c) An existing user and competing applicant with an earlier priority date may object to the applicant-specific solution within 30 business days on the grounds that the applicant-specific solution would impede Western Power's ability to provide covered services to that existing user or to provide the covered services that are sought in a competing application ~~to a competing applicant~~with an earlier priority date compared with what the position would be if the applicant-specific solution were not implemented.
>
> (d) Western Power will evaluate the objection within 40 business days of it being lodged and if it agrees that the applicant-specific solution would impede Western Power's ability to provide covered services to an existing user or to provide the covered services that are sought in a~~the~~ competing~~other~~

[631] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 7-8.

[632] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 8.

connection application ~~to a competing applicant~~with an earlier priority date, then it must either decline to offer an applicant-specific solution to the applicant or modify the applicant-specific solution so that the applicant-specific solution would not impede Western Power's ability to provide covered services to an existing user or the covered services that are sought in ~~another~~that other ~~connection~~ application with an earlier priority date~~to a competing applicant~~. If Western Power elects to modify the applicant-specific solution then it must provide a further opportunity to object under clause 20.3(c) to existing users and competing applicants with an earlier priority date that Western Power considers may be impeded by the applicant-specific solution.

(e) If:

(i) no objections are made to an applicant-specific solution; or

(ii) Western Power evaluates under clause 20.3(d) that an applicant-specific solution (whether the original applicant-specific solution or a further applicant-specific solution developed following modification under clause 20.3(d)) would not impede Western Power's ability to provide covered services to an existing user or to provide the covered services that are sought in a competing~~nother~~ connection application ~~to a competing applicant~~with an earlier priority date,

then Western Power within 30 business days must make an access offer to the applicant based on the applicant-specific solution identified in this clause 20.3(e).

2519. Western Power also proposed to insert a new clause (16.5(b)) to provide that where an applicant requests an applicant-specific solution, clause 20.3 will apply and the applicant will be deemed to have requested a study concerning an applicant-specific solution:

16.5 Opt-out of Competing Applications Group Process

(a) An applicant may, at the time of making a connection application under clause 16, elect that the connection application is to be processed as an applicant-specific solution and is not to be considered as part of a competing applications group. ~~Western Power will process such a connection application as an applicant-specific solution and will not consider it as part of a competing applications group.~~

(b) If an applicant makes an election under clause 16.5(a), it will be deemed to have made a request for a study under clause 20.3(a) and clause 20.3 shall apply to the processing of that application.

2520. Additional and related amendments to clauses 24.1(c), 24.3(b) and 24.5(a)(ii)(A) were also proposed to confirm that where an applicant opts for an applicant-specific solution under these clauses, the applicant is deemed to have made a request for study under clause 20.3(a).

2521. Synergy submitted that Western Power's new clause 16.5(b) did not give the applicant the choice of not proceeding with the study or the application. It requested for the applications and queuing policy to clarify that an applicant may choose to withdraw its application, or not proceed with the proposed applicant-specific solution.[633]

[633] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 22, paragraphs 93 and 94.

2522. The ERA considered the proposed amendments were acceptable because they balanced the interests of the applicant against competing applicants and are, therefore, consistent with section 5.7(a) of the Access Code.

2523. In response to Synergy's concern about the ability of the applicant to withdraw its application or not proceed with the applicant-specific solution, the ERA considered the following provisions in the applications and queuing policy address this matter. These provisions were reasonable because they provide certainty and minimise administrative costs to the application process:

- Clause 20.3A of the policy provides that where an applicant seeks a study for an applicant-specific solution, then its application will continue to be considered as part of the CAG unless clause 16.5 applies.
- Clause 16.5 operates as an opt out provision from the CAG. The proposed amendments do not amend this position.
- Where an applicant is unsure of whether it wants to opt out it can request a study under clause 20.3 first, and/or can withdraw its application at any time under clause 3.13 of the policy.
- Furthermore, clause 20.3 requires agreement on the costs of the study to be reached prior to the study commencing. If this cannot be agreed upon, then the application is deemed to be withdrawn.

2524. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

Studies for applicant-specific solutions (ID 8A)

2525. Clauses 24.1(c), 24.3(b) and 24.5(a)(ii)(A) of the applications and queuing policy all state that where an applicant opts for an applicant-specific solution, the application will be processed in accordance with clauses 20.2 and 20.3.

2526. Western Power considered that the current policy was ambiguous as to whether an applicant in this situation must request a study. It submitted that:[634]

> A study relating to the applicant-specific solution is always necessary to investigate the potential applicant-specific solution and to support the objections process under clause 20.3. There is a potential ambiguity in the AQP as to whether an applicant who has opted for an applicant-specific solution under these clauses must request a study under clause 20.3(a).

2527. Western Power proposed to amend clauses 24.1(c), 24.3(b) and 24.5(a)(ii)(A) to confirm that where an applicant opts for an applicant-specific solution under these clauses, the applicant is deemed to have made a request for a study under clause 20.3(a). The proposed amendments included:

- Adding the words "and the applicant will be deemed to have requested a study under clause 20.3(a)" to clause 24.1(c).
- Adding the words *"and the applicant will be deemed to have made a request for a study under clause 20.3(a)"* to clause 24.3(b), along with some other drafting changes to improve readability.

[634] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 8.

- Adding the words *"and the applicant will be deemed to have made a request for a study under clause 20.3(a)"* to clause 24.5(a)(ii)(A), along with other drafting changes to clarify that notification under this clause is notification in writing.

2528. No submissions to the ERA addressed these proposed changes to the applications and queuing policy.

2529. The ERA considered the proposed amendments to clauses 24.1(c), 24.3(b) and 24.5(a)(ii)(A) to be acceptable because they balanced the interests of the applicant against competing applicants. However, the language used in clauses should be consistent where practicable. Hence, the following amendment was to be made to clause 24.1(c) to make it consistent with clauses 24.3(b) and 24.5(a)(ii)(A), which used the words "and the applicant will be deemed to have made a request for a study under clause 20.3(a)".

2530. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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)."

2531. In its revised proposal, Western Power has accepted required amendment 67 and has made the required amendments to clause 24.1(c).[635]

2532. No submissions were received on the draft decision.

2533. The ERA is satisfied that Western Power has complied with draft decision required amendment 67.

Mandatory preliminary assessments (ID 9)

2534. Western Power considered the current wording in the applications and queuing policy results in applicants thinking that a preliminary assessment may not be required. However, it submitted this is not the case:[636]

> In practice, a preliminary assessment is always required, although its nature and scope may vary depending on the nature and constraints affecting a connection application. However, the effect of [current] clauses 18 and 19.1(a) is that a preliminary assessment is optional at the discretion of the applicant. An applicant 'may' request a preliminary assessment when lodging a request for an enquiry under [current] clause 18. Western Power must advise the applicant of the expected completion date of a preliminary assessment if such an assessment has been requested by the applicant under [current] clause 19.1(a).
>
> A preliminary assessment typically provides an assessment of network connection options, and indicative costs and timeframes. Such an assessment is important in the context of an increasingly constrained network as it encourages the early identification of issues that may affect the progression of the applicant's application.

[635] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 240.

[636] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 9.

2535. Western Power proposed to amend clause 19.3, and make related amendments to clauses 18.1(a) and 19.1(a)(i), to confirm that a preliminary assessment is mandatory, unless otherwise agreed by Western Power:

> 19.3 Preliminary Assessment
>
> A preliminary assessment with regards to a connection application may consist of an assessment as to:
>
> …
>
> To avoid doubt, a preliminary assessment must be undertaken in relation to a connection application either before that application is submitted in accordance with a request under clause 18.1 or after that connection application is lodged as advised by Western Power under clause 19.1(a)(i), unless otherwise agreed by Western Power.

2536. The related amendments to clauses 18.1(a) and 19.1(a)(i) were to provide that an applicant may elect for the preliminary assessment to be undertaken at the enquiry stage (i.e. before lodging a connection application), or after the connection application has been lodged. The related amendments were as follows:

> 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 must lodge an enquiry with Western Power to notify Western Power of the proposed connection application, and may request a preliminary assessment under clause 19.3~~, and~~ to occur before lodging the proposed connection application.
>
> (b) Western Power must …
>
> 19.1 Initial Response
>
> (a) Subject to clause 19.1(b), Western Power must provide an initial response to the applicant within 20 business days of receiving the applicant's connection application, specifying:
>
> (i) the time by which Western Power will provide a preliminary assessment under clause 19.3 with regards to the connection application (if ~~requested);~~ such an assessment was not undertaken under clause 18.1 before the connection application was submitted and is required under clause 19.3); and
>
> (ii) the time by which ...

2537. Synergy considered that Western Power's proposed change to clause 19.3 (and related amendments to clauses 18.1(a) and 19.1(a)(i)) would make a preliminary assessment compulsory, irrespective of whether there was actually any real need for such an assessment. It also considered that the proposed change, when read together with the related amendments, was ambiguous:[637]

> [T]he proposed drafting in clause 19.3, when read together with the proposed amendments to clauses 18.1(a) and 19.1(a)(i), is ambiguous – it is not clear that an agreement between the parties that a preliminary assessment is not required works with proposed clauses 18.1(a) and 19.1(a)(i). The current wording in the AA3 AQP better reflects that position.
>
> Synergy notes WP's response to Synergy's request for an explanation of why a preliminary assessment is required in almost every case. However, Synergy reiterates

[637] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 22, paragraphs 97 and 98.

> the view … that as a preliminary assessment is intended, amongst other things, to determine if there is sufficient spare capacity available to support the connection application, WP's proposed change is insufficiently detailed to enable users and applicants to understand how the AQP will operate and at the very least must exclude routine connection applications where spare capacity won't be an issue – for example, in relation to equipment used by residential and small business customers such as PVs and battery systems and now EVs.

2538. The effect of the proposed amendments to clause 19.3 was to make a preliminary assessment compulsory, except where there is agreement between the parties. The ERA considers that in practice a preliminary assessment would be required more often than not, and would generally always be required to at least determine whether there is sufficient spare capacity. For these reasons, the proposed changes to clause 19.3 (and related changes to clauses 18.1(a) and 19.1(a)(i)) were reasonable and consistent with the requirements of the Access Code and the Access Code objective and therefore were accepted.

2539. However, the ERA considered that the drafting of proposed clauses 18.1(a) and 19.1(a) could be improved to address the ambiguity that was raised by Synergy in its submission to the ERA. The following drafting improvements were required by the ERA:

> 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<u>:</u>
>
> <u>(i)</u> must lodge an enquiry with Western Power to notify Western Power of the proposed connection application<u>;</u>~~,~~ and
>
> <u>(ii)</u> may request <u>that </u>a preliminary assessment <u>is undertaken </u>under clause 19.3 <u>prior to the applicant</u>~~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 <u>of</u>~~with regards to~~ the connection application (if such an assessment was not <u>provided</u>~~undertaken~~ under clause 18.1 before the connection application was submitted ~~and is required under clause 19.3~~); and

2540. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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 [paragraph 2539 above].

2541. Mr Davidson's submission on the draft decision included comments on Western Power's initial proposal to amend clause 19.3 as set out in paragraph 2535 above. Mr Davidson submitted the proposed amendment was inconsistent with clause A2.95 of the model applications and queuing policy which states "the preliminary assessment must be provided as soon as practicable after the application is lodged, having regard to the nature of the application."

2542. Mr Davidson submitted:

> … there is no need for last paragraph of Section 19.3 Preliminary Assessment of the Proposed AQP, because Section 18 Enquiry Stage (see subsection 18.2 Applicant may Request Studies and Information) of the Proposed AQP expressly obligates Western Power to assist the applicants to fine-tune their intended connection application into the formal/final connection application.
>
> There is no limit on the number of connection applications an applicant can make, each of which provides transparency and a clear snapshot in time.
>
> The effect of that paragraph is the loss of transparency, clarity and fairness of the connection application process, as it apparently deliberately blurs the otherwise clear boundary, in the Model AQP, between the formal and informal communication, and the rights applicants receive after they submit a formal connection application. Its retention allows for continuation of non-transparent gaming of the system and is detrimental to the trust in the overall process, which was clearly not the intention nor objective of the Access Code and Model AQP.
>
> Finally, removal of the last paragraph of Section 19.3 Preliminary Assessment of the Proposed AQP would improve efficiency of the overall process, because parties will be forced to make timely decisions and bear consequences of their own decisions, which would help to better achieve the Code Objectives.
>
> In conclusion, delete the last paragraph of Section 19.3 Preliminary Assessment of the Proposed AQP and replace it with Clause A2.95 of the Model AQP which reads: "The preliminary assessment must be provided as soon as practicable after the application is lodged, having regard to the nature of the application".

2543. The intent of Western Power's amendment to section 19.3 was to make clear that a preliminary assessment is mandatory unless otherwise agreed by Western Power. The timing requirements for preliminary assessments are set out elsewhere in the applications and queuing policy.[638]

2544. In its revised proposal, Western Power accepts draft decision required amendment 68 in principle with modifications.[639]

> 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).
>
> 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.
>
> 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.

2545. No further submissions were received on the draft decision.

[638] See section 19.1 of the applications and queuing policy which sets out requirements for Western Power's initial response to an applicant's connection application.

[639] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 241-242.

2546. The ERA agrees retaining the wording "and is required under clause 19.3" ensures consistency and clarity. The ERA is satisfied that Western Power has complied with draft decision required amendment 68.

Deemed withdrawal (ID 10)

2547. Western Power submitted that clause 24.5 sets out how an applicant may reject or accept a PAO, but does not detail the consequence if an applicant provides no response (for instance, a competing applications group member who has received a preliminary access offer may not respond at all). It submitted that:[640]

> Western Power and applicants will benefit from a clear and unambiguous explanation of the consequences of an applicant failing to respond to a PAO within the stated timeframe. An applicant failing to respond to a PAO can create difficulties for Western Power in progressing the applications of other CAG applicants. Western Power cannot compel an applicant to respond. Deemed withdrawal of an application enables Western Power to progress the applications of CAG members who have accepted a PAO without delays caused by considering the position of applicants who failed to respond to the PAO.

2548. Western Power proposed to include a new clause 24.5(c) as follows.

> <u>(c)</u> <u>If an applicant does not respond to Western Power within 30 business days of receipt of the preliminary access offer by one of the methods in clause 24.5(a), the application and any associated electricity transfer application shall be deemed to have been withdrawn.</u>

2549. No submissions on Western Power's initial proposal addressed Western Power's proposal to insert new clause 24.5(c).

2550. The proposal to insert new clause 24.5(c) was accepted because it was consistent with the requirements of section 5.7(b) of the Access Code – the clause enables users and applicants to understand how the policy will operate.

2551. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision of accepting clause 24.5(c).

Termination of a competing applications group (ID 11)

2552. Western Power submitted that there is no mechanism in the current applications and queuing policy to terminate or disband a CAG – once created, the CAG will remain in existence indefinitely. Western Power submitted:

> This creates potential issues and uncertainties for Western Power regarding whether it must, and how it can, continue to progress these applications within the CAG. Where the CAG works are not viable, there may be no alternative shared works that could provide the CAG members with access and therefore no possible CAG solution. It can also create uncertainties for applicants regarding when and how their connection application may be satisfied. Such issues may be exacerbated over time if other CAG members seek applicant-specific solutions or withdraw their applications.
>
> This issue cannot be dealt with contractually. Western Power has the contractual right to terminate its competing applications processing contracts with CAG members if it considers that it is unlikely to make PAOs or access offers to CAG members or if it

[640] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 9-10.

considers that the shared works comprising the CAG solution are no longer viable. However, if Western Power terminates such contracts, the CAG still remains on foot for the purposes of the AQP.

2553. Western Power proposed to insert a new clause (24.7A) into the policy to allow for the termination of a CAG. The proposed clause was as follows:

24.7A Termination of a Competing Applications Group

(a) Western Power may terminate a competing applications group by written notice to the applicants within that competing applications group where:

(i) Western Power considers, in accordance with this applications and queuing policy, that it will not issue notices of intention to prepare preliminary access offers or preliminary access offers or access offers, as applicable, in respect of a single set of works for shared assets to any of the applicants within the competing applications group; or

(ii) Western Power considers that a single set of works for shared assets is no longer viable.

(b) To avoid doubt, where Western Power terminates a competing applications group under clause 24.7A, the applications previously within that competing applications group and their priority date shall not be affected and may be considered for inclusion in other competing applications groups.

2554. No submissions on Western Power's initial proposal addressed Western Power's proposal to insert new clause 24.7A.

2555. The proposal to insert new clause 24.7A was accepted because it was consistent with the requirements of section 5.7(b) of the Access Code – the clause enables users and applicants to understand how the policy will operate.

2556. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision of accepting clause 24.7A.

Exceeding maximum levels (ID 12)

2557. Western Power proposed to amend the title of this clause from "Exceeding Minimum Levels" to "Exceeding ***Maximum*** Levels" (***emphasis*** added). The drafting of the clause remained unchanged.

2558. Western Power submitted the change was necessary to correct a drafting error – clause 24.6C related to circumstances where *maximum* levels for acceptance of access offers are exceeded, not minimum levels. The amendment aligned the title of the clause with the content of the clause.[641]

2559. No submissions on Western Power's initial proposal addressed this proposed change.

2560. The ERA considered the amendment was of an administrative nature that was required to correct a typographical error.

[641] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 10.

2561. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

Notice of intention (ID 13)

2562. Western Power considered the current drafting of clauses 24.2 and 24.4 of the applications and queuing policy was inconsistent.

2563. Western Power submitted that to issue a NOI or PAO to members of a CAG it must consider that a single set of works for shared assets may meet some or all of the requirements of the CAG. However, the current drafting of clauses 24.2 and 24.4 were inconsistent. Western Power proposed to amend clause 24.2 to correct the inconsistency as follows:

> 24.2 Notice of Intention to Prepare a Preliminary Access Offer
>
> Where Western Power considers that a single set of works for shared assets may meet some or all of the requirements of ~~the applicants within~~ a competing applications group, it will issue a notice of intention to prepare a preliminary access offer to all applicants within that competing applications group, and charge a preliminary offer processing fee~~ (provided that such~~. To avoid doubt, the preliminary offer processing fee is not payable by an applicant who under ~~clause~~clauses 24.3(b) or 24.3(c) elects to opt out of the competing applications group or who under clause 24.3~~(c)~~(d) withdraws their application~~)~~.

2564. Western Power submitted that the proposed amendment mirrors the wording used in clause 24.4, which stated:

> 24.4 Western Power's Actions Following Response to the Notice of Intention to Prepare a Preliminary Access Offer
>
> Following the response of applicants under clause 24.3 (if any), Western Power may, if it continues to consider that a single set of works for shared assets may meet some or all of the ***requirements of a competing applications group***, make preliminary access offers to each applicant within the relevant competing applications group at the same time. Western Power will … (***emphasis*** added)

2565. Western Power considered that the wording of clause 24.4 reflected its considerations when deciding whether to issue a NOI or PAO (that is, the proposed CAG solution will meet some or all of the requirements of the group). The CAG solution is assessed on the *collective interests within the group*, rather than the *individual interests of each applicant*. Other applicant-specific issues (for example, individual connection works) should not affect Western Power's assessment of the CAG solution – the CAG solution focuses on the common interests of the members of the group and the desire to share the costs of certain shared works.[642]

2566. Synergy did not agree with Western Power's proposal to amend clause 24.2 and submitted the following:[643]

> … an effect of WP's proposed amendment to clause 24.2 is, when deciding whether to issue a notice of intention under clause 24.2, WP would no longer need to have regard to the requirements of individual applicants within a CAG; instead it would need

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[642] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 11-12.

[643] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, pp. 23-24, paragraphs 103 to 110.

> only consider the requirements of the CAG as a whole. This is inconsistent with the Access Code objective and section 5.7(a) of the Access Code.
>
> CAGs are created by WP grouping together competing applicants as it considers necessary. In Synergy's view, there is no guarantee the members of a CAG have common requirements (indeed there are competing applicants with different interests).
>
> Synergy does not consider WP has properly substantiated (consistent with the Access Code objective) why it should be allowed to not take into account the particular requirements of any individual applicant and look only at what (it thinks) are the common requirements of the CAG. Doing so risks denying consideration of individual requirements that are important for an individual applicant within the CAG.
>
> WP [has] noted that use of the word "continues" in clause 24.4 suggests the wording used in both clauses (clauses 24.2 and 24.4) should be the same. Synergy reiterates [that] the word "continue" does not necessarily mean one must choose the clause 24.4 wording over the clause 24.2 wording. Indeed, the word "continues" would seem to more strongly argue for a continuation of the use of the clause 24.2 wording into clause 24.4.
>
> Synergy requests clause 24.4 should be amended to include the words "the applicants within"…
>
> The wording used in clause 24.2 in the AA3 AQP should be retained for AA4 – i.e. the words "the applicants within" should be not removed.
>
> Synergy reiterates the view [that] to the extent the effect of WP's proposed changes allows CAG requirements to prevail over an individual CAG applicant's requirement, [this] would appear to create a form of bypass in relation to how applications are prioritised.

2567. The ERA considered Western Power's proposed amendments were consistent with the requirements of the Access Code and were accepted for the following reasons:

- Deleting the words "the applicants within" (a competing application group) in clause 24.4 changed the emphasis of the clause from considering the interests of the *individual* applicants within the group to assessing the *collective* interests of the group as a whole. Further, any changes to clause 24.2 was to be reflected in clause 24.4 (and vice-versa) to make the clauses consistent in drafting (language).
- The intention behind the provisions for the CAG was for applications to be assessed on a *collective* basis. This interpretation was supported by clause 24.1(a) of the policy, which provided that Western Power would *assess* "a single set of works for shared assets required to meet some or all of the requirements of each competing applications group". This enabled Western Power to compare the interests of one group against another.
- The proposed amendments were consistent with section 5.7(a) of the Access Code, which provides that the policy "must to the ***extent reasonably practicable*** accommodate the interests of the service provider, users and applicants" [***emphasis*** added]. In situations where there are large numbers of applications it is reasonable to consider the applications as a collective. Where an applicant wants to be considered independently it can opt out of the group and apply for an applicant-specific solution.

2568. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

Payment of fees and contributions policy (ID 22)

2569. Western Power considered that the wording of clause 24.3(a) may be inconsistent with actual practice and should be clarified. It submitted that:[644]

> The contributions policy regulates the manner in which contributions are calculated and this does not need to be dealt with in the AQP in any detail. For example, the contributions policy deals with the situation of an applicant paying an amount greater than its contribution determined in accordance with that policy. Further, if the components of a fee paid are not able to be capitalised because they relate to operating expenses, those amounts would not affect the calculation of any contribution. Therefore, the wording of clause 24.3(a) is potentially inconsistent with actual practice and ought to be clarified to enable the contributions policy to take precedence.

2570. Western Power proposed to amend the drafting of clause 24.3(a) as follows:

> **…** 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~~, or where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract~~; or

2571. A similar amendment was also proposed for clause 24.5(b), which is discussed at paragraph 2580 below.

2572. Alinta submitted the following comments in response to Western Power's proposal to amend clause 24.3 of the policy:[645]

> While Alinta agrees in principle that this scenario should be dealt with in the correct policy, and on face value, the contributions policy appears the most appropriate place for it, Alinta considers that it is not immediately clear how an applicant paying an amount greater than its contribution will be dealt with in the contributions policy as it currently stands.
>
> As such, Alinta considers that greater clarity is required in the contributions policy as to how it deals with any [preliminary access offer] fee exceeding any contribution payable under the contributions policy, and whether any excess payments will be offset against amounts payable under an access contract.

2573. The ERA agreed that the contributions policy does not deal with the situation where an applicant pays a greater amount in the processing fees than its contribution. Hence, the proposed deleted words in clause 24.3(a) should be reinstated in the applications and queuing policy, with the word "or" replaced by the word "and" as follows:

> (a) … 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, and~~or~~ where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract; or

2574. The ERA's draft decision required the following amendment to Western Power's proposal.

[644] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 12.

[645] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 3.2.

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 [paragraph 2573 above] 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”.

2575. In its revised proposal, Western Power has not accepted draft decision required amendment 69. Western Power submits:[646]

> 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

[646] Western Power, Revised AA4 proposal: Response to the ERA’s draft decision, 14 June 2018, pp. 242-243.

is not compatible with the operation of the AQP and the contributions policy in a non-discriminatory manner and therefore should not remain.

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.

Western Power has not made any further changes to the Revised AQP in relation to this required amendment.

2576. The ERA maintains its view that applicants should be refunded amounts of the processing fees paid that are in excess of the contribution payable, subject to Western Power's reasonable processing costs being paid. However, the issues Western Power raises with the offsetting amounts paid in excess of the contribution against amounts due under the access contract are valid. As Western Power indicates, it is possible the CAG applicant and holder of the access contract will be different parties and it would not be correct to pay a CAG applicant's refund to the access contract holder. In such cases, it should be possible to refund the CAG applicant directly.

2577. The ERA agrees with Western Power that, as the refund obligation is effected in the contribution policy, the reference to the requirement in the AQP can be dispensed with.

2578. Western Power's comments about treating CAG and non-CAG applicants differently is not correct. The preliminary offer processing fee is specific to the CAG process, and does not apply to non-CAG applicants so the situation would not arise.

Required Amendment 54

Western Power must ensure there is a mechanism for refunding to the CAG applicant any amount of processing fees paid in excess of the contribution payable.

Payment of fees and contributions policy (ID 23)

2579. As with the proposed changes to clause 24.3(a) (refer to paragraph 2569 above), Western Power submitted that the contributions policy regulates the manner in which contributions are calculated, and hence, this does not need to be dealt with in the applications and queuing policy.[647]

2580. Drafting amendments were proposed for clause 24.5(b) to improve readability, delete some words and clarify that the fee will be counted towards a contribution *where permissible* under the contributions policy:

(b) Where applicants respond under either clause 24.5(a)(i) or an agreement is reached regarding the form of the preliminary access offer under clause 24.5(a)(ii)~~, they~~ ("preliminary acceptance"), the applicants must pay within 30 business days a preliminary acceptance fee as specified in the price list

[647] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 12-13.

> to Western Power ~~as a demonstration of~~to demonstrate the good faith ~~in~~of their intention to proceed to an access contract. The preliminary acceptance fee is non-refundable but, where the applicant subsequently enters an access contract, the preliminary acceptance fee will be counted towards any contribution payable, where permissible under the contributions policy~~, or where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract~~.

2581. No submissions on Western Power's initial proposal addressed Western Power's proposed amendment to clause 24.5(b).

2582. Western Power's proposed amendments were broadly consistent with the requirements of the Access Code on the basis that the amendments improve drafting and add clarity.

2583. The inclusion of the words "where permissible" was consistent with the words used in clause 24.3(a). However, the ERA considered the language used in clauses should be consistent where practicable. Hence, for clause 24.5(b) the deleted words "where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract" was to be reinstated for the reasons set out in paragraph 2573 of this draft decision, to make the clause read:

> (b) … The preliminary acceptance fee is non-refundable but, where the applicant subsequently enters an access contract, the preliminary acceptance fee will be counted towards any contribution payable, where permissible under the contributions policy, and where it exceeds any contribution payable under the contributions policy, the excess will be offset against amounts payable under that access contract.

2584. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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 [paragraph 2583 above] 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".

2585. In its revised proposal, Western Power has not accepted draft decision required amendment 70. Western Power submits:[648]

> 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).

2586. Similar to the comments in the previous section, Western Power must ensure there is a mechanism for refunding to the CAG applicant amounts of the processing fees in excess of the contribution payable.

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[648] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 244.

Required Amendment 55

Western Power must ensure there is a mechanism for refunding to the CAG applicant amounts of the processing fees in excess of the contribution payable.

Modified plant compliance with the technical rules (ID 23A)

2587. In its initial proposal, Western Power considered amendments were required to ensure an applicant must provide information regarding compliance with the Technical Rules in its connection application. It submitted that:

> The compliance of any modifications to generating plant sought in a connection application under clause 16.3 with the Technical Rules is relevant to Western Power's assessment of that connection application. The applicant should be required to provide information relating to such compliance when submitting its connection application, as specified in the application form. As compliance with the Technical Rules is of paramount importance under the Code for Western Power and applicants/users, it is critical that compliance with the Technical Rules is monitored closely. Such information is necessary for Western Power to assess and process the connection application and proposed modification to the generating plant to seek to ensure the safe and reliable operation of the network.
>
> The AQP does not currently include an express requirement for such information to be provided with a connection application to modify generating plant, as specified in the application form. The proposed amendment is consistent with clause 3.7(e) of the AQP which requires connection applicants to provide such information about the facilities and equipment at the connection point to the extent required by the Technical Rules and Western Power acting as a reasonable and prudent person.

2588. Western Power proposed to amend the drafting of clause 16.3 to add the words "and compliance of the modified generating plant with the technical rules" as follows:

> If an applicant seeks to materially change the characteristics of generating plant connected at a connection point, 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.

2589. In its submission on Western Power's initial proposal, Synergy considered the applications and queuing policy should "be more specific about the scope of the information that could be required by Western Power under this amended clause". It was also concerned about Western Power being able to impose a higher compliance standard:[649]

> Compliance with the technical rules is a very broad concept which could impose obligations on small users to establish complex compliance plans and risk matrix in respect of small generating plant and spend a significant amount of time and cost managing customer queries in relation to what facilities and appliances materially modifies the network/connection point. Synergy assumes this is not WP's intent and requests this to be reflected in the drafting.

[649] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 21, para. 89.

> Synergy is also concerned to ensure WP's proposed amendment does not impose a higher compliance standard than parties are currently subject to. For example, the reference to the technical rules in the amendment should be changed to ensure the standard of compliance required is to the technical rules that apply to the user or applicant. This will ensure that grandfathered arrangements can continue to apply and will not impose unreasonably burdensome obligations on users, which could result in necessary or desirable modifications not being made to generating plant.

2590. The ERA considered that, while Synergy had raised a valid point, the clause includes the words "as a reasonable and prudent person might require". This wording provides flexibility to impose a lower information and/or compliance burden on small users where appropriate. For this reason, the proposed amendment to clause 16.3 was consistent with the requirements of the Access Code and the Access Code objective.

2591. Submissions from the Australian Energy Council and Synergy both commented on the ERA's draft decision that Western Power's proposed amendment to clause 16.3 was consistent with the requirements of the Access Code.

2592. The Australian Energy Council considers reliance on "what a reasonable and prudent person might require" does not provide sufficient clarity concerning Technical Rules compliance.[650]

2593. Synergy submitted:[651]

> The proposed amendments to clause 16.3 are contrary to the Access Code objective of promoting the economically efficient investment in, and operation and use of, networks and services of networks in WA to promote competition in markets upstream and downstream of the networks. This is because the proposed amendments are likely to have significant operational implications for users, including Synergy. In so far as Synergy is concerned, Synergy's Retail Business Unit regularly processes applications for PV systems (which fall within the definition of 'generating plant') for small use customers. To comply with proposed clause 16.3, Synergy would need to demonstrate how each and every technical rule is met in its connection application. This is unworkable.
>
> Synergy submits the operational impact to Synergy of WP's proposed amendments is contrary to section 5.7(b) of the Access Code, which requires that an AQP be sufficiently detailed to enable users and applicants to understand in advance how the policy will operate.
>
> If, however, the ERA is minded to approve WP's proposed amendments in its final decision, Synergy suggests the Access Code defined term "good electricity industry practice" be added to clause 16.3 as set out below (Synergy's proposed amendments in underline). In Synergy's view, this will reduce the burdensome obligations that would otherwise apply if WP's proposal is approved without amendment.
>
> "If an applicant seeks to materially change the characteristics of generating plant connected at a connection point, 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 modes) that WP, as a reasonable and prudent person, <u>and acting in accordance with good electricity industry practice</u>, might require

[650] Australian Energy Council, *ERA draft decision on proposed revisions to the access arrangement for the Western Power network*, 13 June 2018, p. 8.

[651] Synergy, *Economic Regulation Authority draft decision on proposed revisions to the access arrangement fort the Western Power network*, June 2018, p. 57.

> to assess the impact of the modification on the network and other users, and compliance of the modified generating plant with the Technical Rules."

2594. The ERA agrees the concerns raised by Synergy and the AEC are valid but it is not practicable to expect that every situation (and the information required in that situation) will be detailed in the clause.

2595. The ERA agrees with Synergy's suggestion to add "and acting in accordance with good electricity industry practice" as this would ensure industry standard practice is taken into account.

Required Amendment 56

Clause 16.3 must be amended as follows:

"… as a reasonable and prudent person, <u>and acting in accordance with good electricity industry practice</u>, …"

Information requirements for connection applications (ID 23B)

2596. Clause 3.7 details the information that the applicant must provide to Western Power at the time of submitting its connection application.

2597. Western Power noted that the facilities and equipment which may ultimately be installed at a connection point may differ from those contemplated at the time that a connection application is made. It considered that clause 3.7(e) should be clarified to confirm that:[652]

> an applicant must provide information about facilities and equipment which are technically required, but it is acknowledged that there may be some additional aspects of facility and equipment which could be subject to change, such as the particular generating plant that a generator may seek to connect.

2598. Existing clause 3.7(e) requires the applicant to provide information about the facilities and equipment to be connected at the connection point to the extent required by the Technical Rules and by Western Power acting as a reasonable and prudent person. Western Power proposed to amend the drafting of clause 3.7(e) to as follows:

> 3.7 Information Required with Connection Applications
>
> The applicant must provide the following information to Western Power in respect of a connection application at the time of submitting the connection application:
>
> …
>
> (e) such information regarding the facilities and equipment <u>likely or required to be connected</u> at the connection point to the extent required by:
>
> (i) the technical rules; and
>
> (ii) Western Power acting as a reasonable and prudent person,

[652] Western Power, *Access arrangement information: Attachment 12.3 [redacted]*, 2 October 2017, p. 14.

2599. Perth Energy raised the following concerns over the requirements of clause 3.7:

- Whether the requirements were feasible to implement and whether unnecessary restrictions were being placed on potential applicants.
- Existing holders of capacity appear to be able to move access from one location to another, and from one generation type to another, without undertaking the same level of analysis that would be applicable to a new connection.

2600. Perth Energy submitted:[653]

> The current clause 3.7(e) requires any proponent wishing to submit an access application to:
>
> "provide information regarding the facilities and equipment at the connection point to the extent required by: i) The technical rules; ii) Western Power acting as a reasonable and prudent person"
>
> Perth Energy notes the requirement to provide information as per the technical rules may not be possible to achieve in practice. Information required in the technical rules can only be provided once a proponent has made a commitment to the specific type and model of generating unit to be installed; which requires the proponent to place an order for the chosen machine. Perth Energy is of the view that placing this obligation on the proponent prior to the negotiation of network connection is excessive.
>
> Rather, Perth Energy would recommend it to be sufficient that the proponent describes the proposed type of plant and provide generic or typical data. Given the long lead times associated with network connection and associated fast rates of technological change in power generation systems, committing to a manufacturer and make of a model early on the application stage will constrain the best investment decisions being made.
>
> If there is a situation where Western Power really does require all of the information required by the technical rules then it is adequately covered by clause (ii). It can rightly advise that, acting as a reasonable and prudent person, in this situation it needs the information set out in the technical rules.
>
> Perth Energy suggests that deletion of 3.7(e)(i) removes an unnecessary obligation on proponents and that Western Power is adequately protected by 3.7(e)(ii).

2601. The ERA considered the proposed amendments were consistent with the requirements of the Access Code because the amendments reinforce the need for compliance by Western Power and the applicant with the Technical Rules (as required under section 12.4 of the Access Code), but also recognised that the facilities and equipment which is ultimately installed at a connection point may differ from those contemplated at the time that a connection application is made. The insertion of the word "likely" combined with the requirement for Western Power to act as a reasonable and prudent person should have addressed the concerns raised by Perth Energy.

2602. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

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[653] Perth Energy, *Submission the ERA regarding Western Power's proposed revisions to the access arrangement for the Western Power network*, November 2017, pp. 11-12.

Proposed amendments to transfer application provisions

Contestable customers (ID 14)

2603. Western Power considered the current applications and queuing policy was inconsistent with the *Electricity Corporations (Prescribed Customers) Order 2007*. It submitted the following in support of its proposed amendments:

> The AQP considers contestability on an exit point by exit point basis for the purposes of customer transfer requests and making access offers. It contemplates that determinations will be made by Western Power as to whether an exit point is contestable by reference to the estimated amount of electricity to be consumed at that exit point (i.e. the contestability threshold).
>
> This approach is inconsistent with the *Electricity Corporations (Prescribed Customers) Order 2007* which defines a 'prescribed customer' (who therefore cannot be a contestable customer) based on the customer's portfolio of exit points.
>
> This inconsistency creates issues and ambiguities for Western Power and applicants in interpreting and implementing the AQP. Different outcomes could be generated under the order and the AQP regarding who may sell electricity to a customer at a connection point (and therefore be a party to the relevant ETAC).
>
> As a result of the Electricity Corporations (Prescribed Customers) Order 2007, a customer will be 'contestable' if they do not meet the definition of a 'prescribed customer' because the customer consumes, or could reasonably be expected to consume, at an exit point supplying the customer with electricity more than 50MwH per annum.

2604. Western Power proposed to insert "contestable customer" as a new defined term and delete the terms "contestable" and "contestability threshold":

> **"contestable customer"** means a customer to whom the supply of electricity is not restricted under section 54 of the Electricity Corporations Act 2005 or under another enactment dealing with the progressive introduction of customer contestability.
>
> {Note: At the time this applications and queuing policy comes into effect, the relevant instrument under section 54 of the Electricity Corporations Act 2005 was the Electricity Corporations (Prescribed Customers) Order 2007, gazetted 29 June 2007.}
>
> ~~**"contestable"**, with respect to an exit point, means an exit point that Western Power has determined is contestable under clause 13.~~
>
> ~~**"contestability threshold"** in relation to an exit point, means the amount of electricity consumed or the estimated amount of electricity that will be consumed at the exit point, by a customer who is a member of a class of customers declared to be 'prescribed customers' as defined in section 54 of the Electricity Corporations Act 2005 by an order made under and in accordance with section 54(4) of that Act, within the period specified in the declaration.~~

2605. Western Power submitted that given its proposed new term *contestable customer*, and related amendments (outlined below), the definitions of "contestable" and "contestability threshold" (which focus on exit points) were no longer necessary or appropriate, and were therefore deleted.

2606. Other related and consequential amendments arising from the inclusion of the term contestable customer included:[654]

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[654] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 15-16.

- Amendments to clause 13.1 to require Western Power, when it received a transfer application, connection application or transfer request, to determine if the application or request is being made for the purpose of supplying electricity to a contestable customer at the exit point.
- Amendments to clause 13.3 to require Western Power to reject an application if it is not authorised to make an access offer because the customer who will be supplied electricity is not a contestable customer.
- The deletion of (existing) clause 13.2 – the criteria for whether an application or request relates to a contestable customer is set out in the proposed new definition of "contestable customer".
- The deletion of (existing) clause 14.4(c) – the approach of considering the contestability of exit points on an exit point-by-exit point basis is inconsistent with the *Electricity Corporations (Prescribed Customers) Order 2007*.
- Consequential amendments to clause 9.1 to provide that customer transfer requests may be made in relation to *exit points at which electricity will be supplied to contestable customers*, not *contestable exit points*.

2607. Alinta acknowledged that it was desirable to amend the relevant provisions of the applications and queuing policy so that the provisions aligned with the contestability test in section 54 of the *Electricity Corporations Act 2005* and *Electricity Corporations (Prescribed Customers) Order 2007*. However, retailers need to be certain about the contestability status of a customer before an access application is made and once an access contract is entered into. Alinta submitted:[655]

> … retailers – other than Synergy, which is not exposed to full competition - need to have confidence and certainty that:
>
> - a customer it proposes to supply is in fact "contestable" under the new definition in clause 2.1 well before it makes any offer to that customer and certainly before it makes an access application to Western Power, and
> - once it enters into an access contract with Western Power (or adds a connection point under an existing access contract) in relation to the supply of electricity to a customer who is assessed by Western Power as being "contestable", the contract will continue for its full term even if that person's electricity consumption subsequently declines.
>
> Alinta is concerned that the proposed amendments may increase the risks faced by electricity retailers who compete to supply electricity to contestable customers, which ultimately leads to the creation of uncertainty for customers. That is because the amended provisions reduce, perhaps inadvertently, the level of confidence that retailers may have in relation to the two points outlined above. Alinta therefore requests that the ERA carefully consider Western Power's proposed changes to ensure that retailers are not faced with unreasonable levels of risk in relation to the assessment of customer contestability, and that the proposed amendments do not lead to undue levels of uncertainty for the customer.

2608. Change Energy supported the revisions to the applications and queuing policy concerning the change in interpretation of *prescribed customers*. It submitted there are many customers that at an *aggregate level* are contestable, but due to the current policy are not allowed to enjoy the benefits of competition.[656]

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[655] Alinta Energy, *Alinta Energy Submission*, 11 December 2017, section 3.3.

[656] Change Energy, *Submission on AA4*, 11 December 2017, p. 3.

2609. Community Electricity considered Western Power should be held to account for its incorrect interpretation of the prescribed customer order in the past.[657]

2610. Perth Energy supported the clarification of the “contestable” definition and the alignment of the definition with the *Electricity Corporations (Prescribed Customers) Order 2007*. It submitted that removing the ambiguity surrounding contestability is a good outcome.[658]

2611. The ERA considered the submissions received from interested parties. Alinta highlighted a practical risk that retailers need to manage. The ERA considered that this risk should be managed by retailers – it is not for Western Power to manage this risk through the applications and queuing policy.

2612. The issues raised in Community Electricity’s submission regarding Western Power’s previous interpretation of the prescribed customer order were not considered a matter for the access arrangement review.

2613. The proposed definition of “contestable customer” is consistent with the requirements of the Access Code and the Access Code objective because it reinforces that whether a customer is contestable (or not) is a factual question and also resolves the ambiguity around the exit portfolio issue. The consequential amendments were also consistent with the Access Code requirements on the basis that the amendments were needed and generally simplify the policy, with the exception of proposed clause 13.3. The ERA considered that clause 13.3 required amendments to make it easier to understand. The required drafting amendments are set out below:

> 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~~.

2614. The ERA’s draft decision required the following amendment to Western Power’s proposal.

> **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 [paragraph 2613 above].

2615. In its revised proposal, Western Power has accepted draft decision required amendment 71 and has made the required amendments to clause 13.3.[659]

2616. No submissions were received on the draft decision.

2617. The ERA is satisfied that Western Power has complied with draft decision required amendment 71.

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[657] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, p. 5, paragraphs 26 and 27.

[658] Perth Energy, *Submission the ERA regarding Western Power’s proposed revisions to the access arrangement for the Western Power network*, November 2017, p. 12.

[659] Western Power, Revised AA4 proposal: Response to the ERA’s draft decision, 14 June 2018, p. 244.

Multiple trading relationships at a connection point (ID 21)

2618. Western Power proposed amendments to facilitate multiple trading relationships at a connection point. It submitted:

> The AQP only allows one [national market identifier or] NMI and one ETAC per connection point, and does not allow multiple NMIs and/or ETACs at the same connection point. It also only allows for one controller, and one type of exit service, entry service or bidirectional service to be provided, at a connection point.
>
> As a result, the AQP does not have the flexibility to allow for multiple trading relationships to exist at connection points if wider regulatory and legislative reforms occur to enable such arrangements to exist. Such arrangements may require or involve multiple NMIs, ETACs, controllers and/or types of services. An example of such an arrangement involves electricity being purchased at a connection point by a customer who may want to transfer into the network, at the same connection point, excess generation for sale to a third party.
>
> Clause 14.4 of the AQP provides for the splitting of connection points into multiple connection points, however this would require the installation of additional metering infrastructure etc. and may be less efficient.
>
> Amendments to support multiple trading relationships at a connection point in the future, should regulatory reform occur to enable such arrangements to exist, were requested and are supported by a number of stakeholders.
>
> Legislative reforms to enable multiple trading relationships may come into effect during the AA4 period. Western Power's preference is to avoid having to make mid-term amendments to the access arrangement to address the reforms. The provisions only operate if the relevant reforms are introduced.

2619. Western Power proposed to insert a new clause (14.5) into the applications and queuing policy to confirm that if multiple trading relationships at a connection point are permitted by law and all approvals have been given, Western Power may agree to depart from the requirements of clause 14 to the extent necessary to facilitate that arrangement:

> 14.5 Multiple trading relationships at a Connection Point
>
> Notwithstanding clauses 14.1 to 14.5, if multiple trading relationships at a connection point are permitted by law and all necessary approvals have been given for such an arrangement, Western Power and an applicant may agree to depart from the requirements of this clause 14 to the extent necessary to facilitate that arrangement.

2620. An amendment was proposed at clause 3.8 to allow an exception to the requirements for one Electricity Transfer Access Contract (ETAC) for each connection point in such circumstances:

> 3.8 One Electricity Transfer Access Contract per Connection Point
>
> Each connection point must be included in one and only one electricity transfer access contract to allow the transfer of electricity at that connection point, except where multiple trading relationships at a connection point are permitted by law and all necessary approvals have been given for such an arrangement.

2621. Perth Energy supported the extension of clause 3.8 to allow multiple trading relationships at a connection point (subject to necessary legal approvals). [660]

[660] Perth Energy, *Submission the ERA regarding Western Power's proposed revisions to the access arrangement for the Western Power network*, November 2017, p. 11.

2622. Synergy submitted Western Power had not provided any "sound justification" for the proposed amendments to clause 14.5.[661] Synergy provided the following information in response to Western Power's proposal:

> In February 2016, the Australian Energy Market Commission (**AEMC**) decided against making the National Electricity Amendment (Multiple Trading Relationships) Rule 2016 and the National Energy Retail Amendment (Multiple Trading Relationships) Rule 2016 (MTR Rules).
>
> The AEMC defined the term "multiple trading relationships" to refer to the ability of a customer to engage with multiple retailers at a premises, noting that a customer who wishes to engage with multiple retailers can do so by establishing a second connection point at a premises.
>
> The AEMC explained in its final rule determination into the MTR Rules (dated 25 February 2016) the costs of establishing new connection points were identified to be much lower while considering the report than was anticipated by the Australian Energy Market Operator when it proposed the MTR Rules to the AEMC.
>
> However, it is not clear to Synergy whether WP has adopted a concept of multiple trading relationships that aligns with that of the AEMC or whether WP instead proposes a broader class of potential traders, possibly including financial contracts and block-chain technology. This lack of specificity is troubling because it gives rise to the possibility WP may simply assert a set of contractual arrangements constitute multiple trading arrangements and require a user, applicant or market participant that disagrees with a given proposal to, without certain foundation, refute this position.
>
> This ambiguity is concerning because it is likely to be resolved only through time consuming and expensive dispute resolution arrangements or will see applicants and users agreeing with WP or otherwise settling for sub-optimal outcomes because they wish to avoid delay and expense. In any case Synergy reiterates the concerns expressed in its Initial Submissions that, as drafted by WP, the proposal is vague (e.g. "multiple trading relationships" is not defined) and seeks to give WP a unilateral right to "agree to depart from" clause 14 of the AQP without regard to the interests of applicants or users.

2623. The ERA agreed it would be preferable to have certainty about any regulatory regime that allows multiple trading relationships before amending the applications and queuing policy. However, the ERA considered Western Power's proposed amendment was likely to be sufficient to cover any such regime. The ERA considered the proposed words "Western Power and an applicant may agree to depart from the requirements of this clause 14 to the extent necessary to facilitate that arrangement" allows applicants and users to understand in advance how the policy will operate, and is therefore consistent with the requirements of the Access Code. In any case, if issues arise or further amendments were required, sections 4.38 and 4.41A of the Access Code allow the ERA to approve mid-period revisions.

2624. Submissions from the Australian Energy Council and Synergy both comment on the ERA's draft decision about multiple trading relationships at a connection point (proposed new clause 14.5).

2625. The Australian Energy Council submitted the "concept of multiple trading relationships still requires greater specificity to reduce market uncertainty".[662]

[661] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, pp. 20-21, paragraphs 79 to 86.

[662] Australian Energy Council, *ERA draft decision on proposed revisions to the access arrangement for the Western Power network*, 13 June 2018, p. 8.

2626. Synergy submitted:[663]

> WP's proposed amendments to clauses 3.8 and 14.5 of the AQP are contrary to the Access Code and are highly problematic for users and applicants alike. In this submission, Synergy sets out its view of the proposed operation of WP's amendments and the potential impact of this on users.
>
> For the reasons set out below, in Synergy's view, approving WP's proposed amendments to clauses 3.8 and 14.5 of the AQP is contrary to sections 5.7(a) and 5.7(b) of the Access Code.
>
> **Uncertainty**
>
> Synergy remains concerned the concept of multiple trading relationships lacks specificity and is therefore commercially unworkable. As the ERA has pointed out, sections 4.38 and 4.41A of the Access Code allow the ERA to approve mid-period revisions. Synergy considers that, in view of the uncertainty and the need to ensure the AQP complies with (amongst other things) section 5.7(b) of the Access Code, the proposed amendments should be rejected and any revisions to the AQP to deal with the introduction of multiple trading relationships be considered at a time when there is clarity on the legal status of multiple trading relationships in the SWIS.
>
> **Permitted by law**
>
> In its draft decision, the ERA assumes that multiple trading relationships can only be introduced by means of a "regulatory regime", which presumably, will be subject to some form of governmental or independent regulatory oversight. However, in Synergy's view, WP's proposed clause 14.5 is drafted in a manner that should give no confidence to the ERA or the market that any formal regulatory process need be established to allow for multiple trading relationships to be introduced.
>
> Proposed clause 14.5 states:
>
> 'Notwithstanding clauses 14.1 to 14.5, if multiple trading relationships at a connection point are <u>permitted by law</u> and all necessary approvals have been given for such an arrangement, WP and an applicant may agree to depart from the requirements of this clause 14 to the extent necessary to facilitate that arrangement.'
>
> (<u>emphasis</u> added).
>
> The definition of 'law' in the AQP is broad. The definition provides:
>
> "Law" means "written law" and "statutory instruments" as defined in the Code, orders given or made under a written law or statutory instrument as so defined or by a government agency or authority, Codes of Practice and Australian Standards deemed applicable under a written law and rules of the general law including the common law and equity.
>
> "Permitted" by law, in respect of conduct, does not mean that a particular law needs to make provision for a thing. It is sufficient the conduct is not prevented by the law. There is, for example, no law against whistling while driving. It is therefore correct to say that whistling while driving is permitted by law.
>
> Further, while the term "government agency or authority" is not defined, on its ordinary meaning, the term may include directions made by the Minister for Energy, the Public Utilities Office, orders given or made by a government agency – for example, the Public Utilities Office – that means that multiple trading relationships are permitted to occur on, for example, a trial basis.
>
> Having regard to these considerations and despite the lack of specificity around the term "multiple trading relationships", arguably the only current provisions in any "law" that precludes multiple trading relationships from being "permitted by law" are contained in clause 14 of the AQP. For example, in at least some circumstances, the

[663] Synergy, *Economic Regulation Authority draft decision on proposed revisions to the access arrangement fort the Western Power network*, June 2018, p. 52-56.

requirement that a connection point must have one and only controller at the connection point is likely to preclude multiple trading relationships.

If this is the case, then approving WP's proposed clause 14.5 and the text "[n]otwithstanding clauses 14.1 to 14.5", may result in multiple trading relationships being permitted by law.

In such circumstances, it is incumbent upon the ERA to ensure it understands with certainty and clarity what the term "multiple trading relationships" means, what its impact will be upon WP, users, applicants and consumers and whether the regulatory framework in place at present is fit-for purpose.

In making its decision on WP's proposed access arrangement, the ERA is to have regard to the matters in section 26(1) of the ERA Act, including the need to promote transparent decision-making processes.

Having regard to that provision, Synergy considers that WP's proposed amendment does not promote transparent decision-making processes because it is left to a user/applicant to agree with WP whether to depart from the clause 14 process, which may have unintended consequences for the user/applicant in terms of the potential outcomes of negotiations with WP.

Pre-existing contractual rights

In relation to "contracted capacity", Synergy considers users who are presently party to ETACs with WP are granted sole title to the electricity that is transported by WP to or from a connection point.

2627. Synergy provided confidential information to the ERA about its access contracts to support its view that its pre-existing contractual rights would be affected.

Interaction with the Market Rules

As previously submitted, among the many unknown aspects of multiple trading relationships, WP has not made it clear whether parties to the multiple trading relationship must be market participants. Section 5.7(h) of the Access Code requires an AQP to facilitate the operation of Part 9 of the EI Act and the Market Rules. If parties to multiple trading relationships are not "market participants" (as that term is defined in the Market Rules) then it is not clear how the AQP can facilitate the operation of the Market Rules. In the absence of such clarification Synergy does not see how the ERA could approve the proposed AQP amendments.

Inconsistency with rejection of Synergy's proposed capacity demand reference service

Finally, Synergy recognises the need for greater flexibility with respect to new technology and the consumer demand that flows from innovation to offer affordable and innovative services for its customers.

Synergy's required reference services, including the capacity swap and sharing reference services facilitate multiple network users (suppliers or purchasers of electricity) to transact at a connection point without depriving a user exercising its contractual rights in respect of a connection point.

Synergy considers this reference service would better meet the Access Code objective of promoting competition upstream and downstream of WP's networks and be a more effective mechanism for the achievement of multiple users at a connection point than WP's comparatively unclear and uncertain proposal.

2628. In the draft decision the ERA agreed it would be preferable to have certainty about any regulatory regime that allows multiple trading relationships before amending the applications and queuing policy. However, the ERA considered Western Power's proposed amendment was likely to be sufficient to cover any such regime.

2629. Given the matters raised by the AEC and Synergy, particularly the possibility that, depending on how "multiple trading relationships" are defined, a user may be deprived of pre-existing contractual rights to contracted capacity at connection points if it were to be used by multiple users, the ERA considers Western Power's proposed amendments should not be made at this stage.

Required Amendment 57

Western Power's proposed amendments to clauses 3.8 and 14.5 of the applications and queuing policy must be deleted.

Relationship with transfer and relocation policy (ID 15 and 15A)

2630. Western Power considered there is a misconception among users that the applications and queuing policy enables capacity currently contracted to one user being temporarily made available to another user. Western Power considered this was not the purpose of the policy and it had no mechanism to achieve this because capacity transfers and relocations are dealt with under the transfer and relocations policy.

2631. Feedback from Western Power's stakeholder engagement recognised the matter might be best dealt with in the transfer and relocations policy, but suggested any policy should:

- not inhibit implementation of demand side solutions
- not constrain innovation
- not impede peer to peer trading.

2632. Western Power proposed to insert a new clause (12A) into the policy as follows:

> <u>12A Relationship with transfer and relocation policy</u>
>
> <u>(a)</u> <u>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.</u>
>
> <u>(b)</u> <u>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.</u>
>
> <u>(c)</u> <u>If a relocation the subject of an electricity transfer application under clause 12A(b):</u>
>
> <u>(i)</u> <u>requires an augmentation or any work to be completed to enable the increase or decrease in contracted capacity at the relevant connection point; or</u>
>
> <u>(ii)</u> <u>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,</u>

then the applicant must submit a connection application and the requirements of that application must be satisfied before the relocation can occur.

2633. The following note was added to clause 10.2, which refers to the new proposed clause (12A):

10.2 Increase or Decrease in Contracted Capacity

(a) An electricity transfer application to increase or decrease contracted capacity with respect to an existing covered service under the applicant's access contract may be made by notice to Western Power.

{Note: clause 12A concerns the application of the transfer and relocation policy to relocations.}

2634. Definitions of "assignment" and "bare transfer" were added to clause 2.1:

- "Assignment" had the meaning given to 'assignment' in the transfer and relocation policy.
- "Bare transfer" had the meaning given to 'bare transfer' in the transfer and relocation policy.

2635. Western Power submitted that:[664]

- New clause 12A(a) was included to confirm that the transfer and relocation policy (and not the applications and queuing policy) applies to bare transfers and assignments of rights under an access contract, including temporary transfers.
- New clauses 12A(b) and (c) were included to confirm that if a user wishes to seek a relocation under the transfer and relocation policy, it must lodge an electricity transfer application. A connection application must also be lodged if the relocation requires any augmentation or works, or would result in Western Power's ability to provide covered services to another user or applicant being impeded.
- The new clauses reflect the existing principle in clause 10.2 – that if a change (for instance, relocation or increase in contracted capacity) requires works to augment the network or will impede another user or applicant, a connection application is required.

2636. Synergy submitted: [665]

The AQP is intended to deal with "access applications" by "applicants" and by definition, they relate only to modification to an existing contract for services or the establishment of a new one. In Synergy' regulatory view, it needs to be made clear in the AQP that clause 10.2(a) only applies if the increase/decrease involves a modification to an existing contract for services or the establishment of a new service.

It is therefore premature for the AQP to assume all or any increases, decreases or relocations of capacity will necessarily require an access application to be made.

2637. The ERA agreed with the points raised by Synergy – by definition, the applications and queuing policy is intended to deal with new or modified services. As currently

[664] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp.17-18.

[665] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, pp. 18-19, paragraphs 69 to 71.

drafted, Western Power's proposed new clause (12A) ignored this distinction and for this reason was not accepted.

2638. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 72**
>
> Proposed new clause 12A ("Relationship with transfer and relocation policy") must be deleted from the applications and queuing policy.

2639. In its revised proposal, Western Power has not accepted draft decision required amendment 72. Western Power submits:[666]

> 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.
>
> 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.
>
> 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.*
>
> 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.
>
> 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.
>
> 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.

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[666] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 245-247.

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*.

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.*

2640. Western Power's revised proposal would result in a similar position as its initial proposal to add the proposed new clause 12A. The reasons for rejecting new clause 12A in the draft decision, apply equally to the amendments subsequently proposed by Western Power.

Required Amendment 58

Western Power's proposed amendments to clauses 10.2(a), 16.2(a), 16.3 and 16.4 (as set out in paragraph 2639 above, must be deleted.

Connection point configuration (ID 16)

2641. Western Power submitted that existing clause 14.3, which covers the combination of multiple connection points into a single connection point, does not expressly state that the consent of an existing retailer is required.[667]

2642. Western Power proposed to insert a new clause (14.3(d)) into the applications and queuing policy to confirm where an application to combine multiple connection points

[667] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 19.

within a single connection point is made by an applicant, who is not the retailer in relation to all relevant connection points, the applicant must obtain the consent of the retailer:

> (d) Where an application is made under clause 14.3(a) by an applicant who is not the retailer in relation to a relevant connection point, the applicant must obtain the consent of the retailer.

2643. Similar to existing clause 14.3, existing clause 14.4, which covers the splitting of a single connection point into multiple connection points, does not expressly state that the consent of an existing retailer is required.

2644. Western Power proposed to insert a new clause (14.4(c)) to confirm that where an application to split a single connection point into multiple connection points is made by an applicant, who is not the retailer for the connection point, the applicant must obtain the retailer's consent.

> (c) Where an application is made under clause 14.4(a) by an applicant who is not the retailer in relation to the connection point, the applicant must obtain the consent of the retailer.

2645. No submissions made to the ERA addressed Western Power's proposed new clauses 14.3(d) and 14.4(c).

2646. Western Power's proposed new clauses were considered consistent with section 5.7(a) of the Access Code because they accommodated the interests of the existing retailer at a connection point.

2647. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

Proposed revisions to common provisions

Covered services (ID 18)

2648. Western Power considered the current applications and queuing policy does not specifically state that it is only applicable to applications for covered services. Western Power considers this may create confusion for property developers not seeking a covered service.

2649. Western Power submitted that:[668]

> Uncertainties and ambiguities can arise for Western Power and property developers regarding how Western Power should process requests by property developers seeking augmentations to the network to service a subdivision but who do not seek an identified covered service. As such applications do not relate to a covered service to be provided to a developer or a third party or seek capacity on the network, a developer is not capable of receiving an 'access offer' or entering an 'access contract', as those terms are currently defined by the AQP. Western Power has other processes in place for processing such applications outside the AQP.

2650. Western Power proposed to insert a new clause (2.2(c)) and make amendments to the definitions of "connection application" and "electricity transfer application" (in clause 2.1) to confirm that the policy only applies to applications seeking a covered

[668] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p.20.

service and to ensure there are no inconsistencies between the defined terms: *connection application*, *access offer* and *access contract*:

(c) To avoid doubt, this applications and queuing policy only applies to applications in relation to covered services.

"connection application" means an application in relation to a covered service lodged with Western Power under this applications and queuing policy that has the potential to require a modification to the network, including an application to:

(a) connect facilities and equipment at a new connection point; or

(b) increase consumption or generation at an existing connection point; or

(c) materially modify facilities and equipment connected at an existing connection point; or

(d) augment the network for any other reason,

~~{Note: this might be, for example, to service a subdivision.}~~

and includes any additional information provided by the applicant in regard to the application.

…

"electricity transfer application" means an application in relation to a covered service lodged with Western Power under this applications and queuing policy seeking to …

2651. Amendments were also proposed to clause 16.4, which covers connection applications to modify or augment the network. Western Power proposed to amend clause 16.4(a) to confirm that the clause applies only to applicants who seek to modify or augment the network *for the purposes of receiving a covered service*. The note to the clause would also be deleted:

(a) An applicant who seeks to modify or augment the network for the purpose of receiving a covered service other than under clause 16.1 must submit a connection application on the applicable connection application form.

~~{Note: This might apply to, for example, a developer seeking to service a subdivision, a builder seeking a temporary supply, or a person seeking to relocate network assets.}~~

2652. Synergy considered that Western Power's proposed amendments to clause 2.2(c) and the definition of "connection application" were inconsistent with the requirements of the Access Code. Synergy submitted the following:[669]

The definition of *covered service* in the Access Code expressly excludes an *excluded service*. Therefore, the effect of specifying in the AQP that a connection application applies only to *covered services* would, along with other changes throughout the proposed AQP, be to exclude the requirement that an *applicant* must submit a connection application in respect of *excluded services* and WP would have no obligation to comply with the AQP in respect of *excluded services*. To the extent WP decided *excluded services* applied, they would therefore be unregulated.

This is contrary to the Access Code because the Access Code is drafted on the basis the AQP applies to *excluded services* and *covered services* alike.

The state government's intent is very clear given the drafting of the definition of *covered services*. This is because the definition of *excluded service* provides the

[669] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, pp. 12-14, paragraphs 34 to 43.

supply of the *service* must be subject to effective competition and the cost of the service ***is able to be excluded*** from consideration for *price control* purposes without departing from the Access Code objective *[**emphasis** added]*. Assessing whether a *service* is an *excluded service* is therefore a question of fact and a question of law, neither of which requires the *service* must be the subject of a determination by the Authority under section 6.33 of the Access Code.

Under section 6.33 of the Access Code, the Authority may determine a *service* to be an *excluded service* for the purpose of review or approval of *price control* in an *access arrangement* (section 6.34 of the Access Code).

The upshot of this is disagreement may arise between WP and *users* about whether or not a particular *service* is an *excluded service* and whether as a consequence the AQP does not apply. Services could, in the estimation of WP and one or more *users* during the course of an *access arrangement period* become *excluded services* and then cease being *excluded services* either because supply of the *services* ceases being subject to effective competition or the *service* is no longer able to be excluded from consideration for *price control* purposes without departing from the Access Code objective.

Further, WP could form a view for the purposes of the AQP that a *service* is an *excluded service* without that same *service* being the subject of a determination under section 6.33 of the Access Code. The formation of such a subjective view, which could lead to a dispute between WP and one or more users could then only be resolved by means of time consuming and costly disputes. Further, in such an event, if the Authority is to *approve* WP's proposed amendments to the definition of "connection application", the effect would be WP could depart from the AQP while the *excluded services* remained, at least for a time, a component of WP's *target revenue*.

Synergy contends either outcome is inconsistent with the Access Code objective, section 5.7(a) and section 5.7(b) of the Access Code.

Further, the AQP does not provide sufficient detail in relation to when *applicants* must make a connection application because it is not clear what constitutes the "…potential to require a modification to the network, including an *application* to … materially modify *facilities and equipment* connected at an *existing connection point*…".

Synergy notes the *reference services*, relevantly, specify the technical eligibility criteria for a person to use *a service*. Therefore, a person could connect and use equipment if they continue to satisfy this criterion. However, based on Synergy's discussions with WP it appears that this is not always the case. In some circumstances WP may require a connection application to be made even if a person's *facilities and equipment* comply with the eligibility criteria for the *reference service (or covered service*). This unilateral and ad-hoc determination does not provide regulatory certainty or clarity to *applicants* and it can be a very costly and time consuming exercise to get a position from WP that is applied consistently to all *users* and *applicants*.

Therefore, Synergy requires the AQP to define and clarify the matters that require a connection application including setting timelines for WP to diligently and expeditiously respond to a *user's/applicant's* queries as to whether a connection application is required in relation to connecting and operating particular equipment or appliances. In Synergy's view, this change will significantly assist Synergy's customers to connect new appliances such as PV, EV and battery as it will remove uncertainty as to what can and cannot be connected without WP's approval, and such a change is consistent with the objective in clause 1.2(c) of the AQP – that is, to facilitate joint solutions for connection applications.

2653. The ERA considered the matters raised by Synergy and decided Western Power's proposed amendments were consistent with the requirements of the Access Code, subject to an additional amendment:

- The proposed drafting was consistent with the requirements of the Access Code. Sections 5.7(d) and (e) of the Access Code specifically provide that the applications and queuing policy is to apply to applications relating to the terms for an access contract for covered services and the process for priority disputes in relation to access for covered services. The term "covered services" as defined in the Access Code expressly excludes *excluded services*. By extension the applications and queuing policy is intended to only apply to covered services.

- The applications and queuing policy does provide sufficient information about when applicants must make a connection application. The definitions "connections application" and "electricity transfer application" indicate when an application is required (i.e. when an application has the potential to require modification to the network or modification to a service).
  - Synergy submitted that the criterion to "materially modify facilities and equipment connected at an existing connection point" was unclear in the definition of “connection application”. Synergy argued that if a change to the facilities or equipment meets the eligibility criteria it should not amount to a material modification.
  - To address Synergy's concern, the ERA considered the words "in a way that means they no longer meet the eligibility criteria" can be added to the end of criterion (c) in the definition of "connection application".
- Additional timeframes for Western Power to respond to queries did not need to be inserted. The process for submitting enquiries and acting expeditiously is already provided for in clause 3.2 and clause 3.12 of the applications and queuing policy. These clauses were considered sufficiently detailed to enable users and applicants to understand how the policy will operate, and hence, satisfy section 5.7(b) of the Access Code.

2654. For the reasons set out above, Western Power’s proposed amendments to (new) clause 2.2(c), the definition of “electricity transfer application” and clause 16.4(a) were consistent with the requirements of the Access Code. The proposed amendment to the definition of “connection application” was accepted subject to the following drafting amendment to address Synergy’s submission:

> **“connection application”** means an application in relation to a covered service lodged with Western Power under this applications and queuing policy that has the potential to require a modification to the network, including an application to:
>
> …
>
> (c) materially modify facilities and equipment connected at an existing connection point <u>in a way that means they no longer meet the eligibility criteria</u>; or

2655. The ERA’s draft decision required the following amendment to Western Power’s proposal.

> **Draft Decision 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 [paragraph 2654 above] to add the words “in a way that means they no longer meet the eligibility criteria”.

2656. In its revised proposal, Western Power states it will accept the required amendment subject to:[670]

[670] Western Power, Revised AA4 proposal: Response to the ERA’s draft decision, 14 June 2018, p. 247.

- 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.

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*;

2657. Submissions in response to the ERA's draft decision about the definition of "connection application" were received from the Australian Energy Council and Synergy.

2658. The Australian Energy Council submitted that the draft decision did not provide sufficient network user clarity as to whether "excluded services" falls under the AQP.[671]

2659. Synergy submitted:[672]

> Synergy submits the ERA's draft decision does not correctly reflect the requirements for an AQP as set out at clause 5.7(c) of the Access Code, namely: the policy must set out a reasonable timeline for the commencement, progressing and finalisation of Access Contract negotiations between the Service Provider and an Applicant, and oblige the Service Provider and Applicants to use reasonable endeavours to adhere to the timeline.
>
> Access Contract is defined in the Access Code to have the same meaning as "access agreement" in Part 8 of the EI Act, being an agreement under the Access Code between a network service provider and another person (a "network user") for that person to have access to services". "Services" is in turn defined in the EI Act to mean "the conveyance of electricity and other services provided by means of network infrastructure facilities and services ancillary to such services".
>
> In contrast, other sub-sections of section 5.7 of the Access Code make reference to "covered services", which relates to "services" provided by means of the "covered network".
>
> In Synergy's view, clause 5.7(c) of the Access Code indicates an intention the AQP should apply to all "Services" provided by the Service Provider.
>
> This important distinction means the AQP must at least establish timelines for processing applications in respect of WP's activities that are not Covered Services, for example, in respect of works undertaken by WP on private networks not related to the

[671] Australian Energy Council, *ERA draft decision on proposed revisions to the access arrangement for the Western Power network*, 13 June 2018, p. 8.

[672] Synergy, *Economic Regulation Authority draft decision on proposed revisions to the access arrangement fort the Western Power network*, June 2018, p. 58.

WP network. It also means WP's proposal for the AQP to be amended to provide it only relates to Covered Services is inconsistent with the requirements of the Access Code and must not be made.

2660. Western Power's rationale for modifying the amendment is (a) to give meaning to the reference "eligibility criteria", as the AQP does not otherwise contain any provisions relating to eligibility criteria; and (b) not to exclude applications likely to adversely impact the security, safety or reliability of the network as a trigger for a connection application, as a connection application has always been and will continue to be necessary in such cases.

2661. The modification to the eligibility criteria is reasonable. Arguably the second trigger, that is, "the modification is likely to adversely impact the security, safety or reliability of the network" is not necessary. However, this would simply fall within "materially modify facilities and equipment" anyway.

2662. The additional matters raised by Synergy are not persuasive, given the structure of section 5.7 of the Access Code, that is, the key operative provisions are expressed to relate only to covered services.

2663. The ERA maintains its draft decision and is satisfied Western Power has complied with the draft decision required amendment.

Confidentiality (ID 19)

2664. Western Power noted that, although applicants consider project-specific information to be confidential as a matter of course, the policy's definition of confidential information requires that the applicant specifies which of the information it provides is confidential. From time to time Western Power has been requested to disclose certain project information to third parties. Western Power proposed to make clearer what project information is not confidential.

2665. Clause 6 of the applications and queuing policy contains provisions for confidentiality:

- Clause 6.1 indicates that information that is required to be disclosed under clauses 18.2A, 24.9(a), 24.9(b) and 24.9(c) is not confidential information.
- Clause 6.2 details the circumstances when confidential information can be disclosed.

2666. Western Power considered that the policy should be clearer about the types of information which it can disclose to competing applicants and the circumstances in which such disclosure may be made. Western Power proposed to amend clause 6.2 to enable it to disclose:

- Confidential information to the market operator (i.e. the Australian Energy Market Operator).
- The information described in clause 29.4(d) to competing applicants in an anonymised format in accordance with that clause and clause 24.10.

2667. Western Power also proposed to amend the definition of "confidential information" (at clause 2.1) to confirm that the information, which is deemed not to be confidential under clause 6.1, did not fall within the definition of confidential information.

2668. The proposed changes to clause 6.2 are set out as follows:

6.2 Confidential Information Must Not be Disclosed

Western Power, an applicant or a disclosing person must not disclose confidential information unless:

(a) the disclosure is made ~~to the Authority~~ on a confidential basis~~; or~~:

(i) to the Authority;

(ii) to the market operator; or

(iii) where necessary for the performance of Western Power's functions; or

(b) the disclosure, where it is made by an applicant or a disclosing person, is made to a worker of Western Power who is bound by an adequate confidentiality undertaking; or

(c) the disclosure is made with the consent of the disclosing person; or

(d) the disclosure is required or allowed by law, or by the Arbitrator or another court or tribunal constituted by law; or

(e) the information has entered the public domain other than by breach of this clause 6.2; or

(f) the information could be inferred by a reasonable and prudent person from information already in the public domain~~.~~; or

(g) the disclosure is made in accordance with clauses 24.9(d) or 24.10.

2669. To give effect to the proposed amendments, Western Power proposed to:

- Insert a new definition of "market operator" (at clause 2.1) as follows:

  "market operator" has the meaning given to the term 'operator' in the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*, which, as at the date this applications and queuing policy comes into effect, is the Australian Energy Market Operator Limited.

- Amend clause 24.9(d) to enable it to disclose certain information to a competing applicant in an anonymised format as follows:

  24.9 Types of Information

  Western Power must make known to any applicant that has lodged an application with Western Power, or to any existing user with an access contract with conditions precedent which have not yet been satisfied or waived:

  …

  (d) ~~except to~~where the ~~extent that it~~application is ~~prevented from doing so by clause 6.2, in respect of each~~ a competing connection application, in respect of each connection application which is competing with that connection application:

  (i) the capacity requirements of the competing connection application; and

  (ii) the geographic location at which the competing connection application seeks the capacity; and

  (iii) reasonable details regarding any augmentation required by the competing connection application~~.~~;

  (iv) any zone substation relevant to providing the covered service sought in the application;

  (v) where the applicant is a generator, the fuel type involved; and

  (vi) the priority date,

in an anonymised format without details of the applicant's name or physical address of any connection point relevant to the application.

- Insert a new clause 24.10(a) to confirm that it can disclose the information in clause 24.9 when issuing notice of intentions, preliminary access offers and access offers as follows:

  24.10 When Western Power Must Update Information

  Western Power must provide the information in clause 24.9:

  (a) ~~unused;~~when issuing notices of intention to prepare preliminary access offers under clause 24.2, preliminary access offers under clause 24.4 and access offers under clause 24.6;

  (b) at any time …

2670. Consequential amendments were also made to:[673]

- Clause 17A.4(a)(ii) to give effect to the intent that Western Power can disclose the confidential information described in clause 29.9(d) for an application that would compete with a prospective application to the prospective applicant.
- Clause 24.10(c) to capture circumstances in which information under clause 24.9(d) is no longer required to be provided in an anonymised format.

2671. Synergy submitted that the disclosure of information under clause 6 should only be made if Western Power had procured the agreement of the recipient to keep such information confidential.[674] It also believed that the proposed changes were contrary to the requirements of the Access Code (namely section 5.7(b) and (d)) and to the legitimate business interests of applicants and users (as contemplated by section 26(1)(d) of the *Economic Regulation Authority Act 2003*.

2672. Synergy submitted the following comments in response to Western Power's proposed amendments to clause 6.2(a):[675]

> On the current AQP drafting, the provision applies only to disclosure to the Authority. Use of the phrase "confidential basis" makes sense because it enlivens the Authority's obligations with respect to such information set out in section 55 of the ERA Act. Disclosure of confidential or commercially sensitive information to the Authority carries a number of protections in addition to those in section 55 of the ERA Act, including in relation to current or former staff members and members of the Authority (section 57 of the ERA Act).
>
> In contrast, Synergy does not understand how requiring disclosure "on a confidential basis" to the system operator or any person provided it is necessary for the performance of WP's functions, does not enliven any comparable statutory obligations in respect of disclosure by WP in general. Nor does the provision require WP to ensure the party to whom confidential information is provided, maintains the confidentiality of the information. This is troubling in the context of disclosure to any person where necessary for the performance of WP's functions because the class of potential disclosures is unusually broad and includes parties to whom disclosure may cause material commercial harm to the party to whom the confidential information pertains.

[673] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 22.

[674] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 11, paragraphs 25 and 30.

[675] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 11, paragraphs 27 to 29.

Further, there is no objective test against which to assess whether the disclosure is necessary for the performance of WP's functions.

2673. The ERA considered that confidential information should not be provided to third parties unless prior consent is obtained or disclosure is required by law. It also noted that if information is provided in an anonymised format under 24.9(d), as proposed by new clause 6.2(g), the information will not by its nature be considered confidential information and hence is capable of being disclosed. Similarly, clause 24.10 applies where anonymity is no longer required.

2674. The ERA agreed with Synergy that proposed new clause 6.2(a)(iii), which allows the disclosure of confidential information "where necessary for the performance of Western Power's functions", was overly broad and was not to be accepted.

2675. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

2676. In its revised proposal, Western Power submits it has accepted draft decision required amendment 74 in principle with modifications.[676]

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.

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).

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.

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.

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.

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.

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

[676] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 248-249.

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.

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~~

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.

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.

2677. It is unnecessary to include the market operator and system management in clause 6.2 as clause 6.2(d) already provides for where the disclosure is required or allowed by law (including the Market Rules). Western Power's proposed amendment does not place sufficient restrictions for providing disclosure to the market operator and system management. If the information is provided outside of a statutory framework, and/or without an element of compulsion, there is no obligation on the receiving parties for the protection of that information. Further, without this requirement Western Power/other parties can effectively choose when and who to provide the confidential information to, which is not appropriate.

Required Amendment 59

Western Power's proposed amendments to clause 6.2(a) to add the market operator and system management must be deleted.

2678. While Western Power proposed that the information specified in clause 24.9(d) would be disclosed in an *anonymised* format without details of the applicant's name or location of any connection point relevant to the application, Synergy suggested that a recipient of such information could "back-calculate" the information in particular situations where it may become self-evident that the information pertains to a particular generator.[677]

2679. As indicated at paragraph 2390 (above), information given in an anonymised format (under clause 24.9(d)) is by its nature not confidential information and can be disclosed. However, as suggested by Synergy, there may be circumstances where it is self-evident which generator the anonymised information relates to. To address such circumstances clause 24.9(d) was to be amended 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. The following amendments were required by the ERA:

> (d) where the application is a competing connection application, in respect of each connection application which is competing with that connection application:
>
> (i) the capacity requirements of the competing connection application; and
>
> …
>
> (vi) the priority date,
>
> in an anonymised format without details of the applicant's name or physical address of any connection point relevant to the application.
>
> 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.

2680. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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 [paragraph 2679 above] 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

2681. In its revised proposal, Western Power has not accepted draft decision required amendment 75. Western Power submits:[678]

> 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

---

677 Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 11, paragraph 25.

678 Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 249-251.

- the works and augmentations Western Power advises are necessary to connect the applicant to the network.

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.

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.

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.

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.

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.

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.

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.

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.

2682. There is a risk that in some circumstances it may be possible to identify the applicant in some anonymised information. This risk will be heightened where the applicants themselves have publicly released project information. It may not be an option for applicants not to announce project details, for example listed entities have reporting obligations. However, competing applicants have a legitimate need to consider the anonymised information when making decisions about their applications in accordance with sections 5.7(a) and 5.7(d) of the Access Code. It is impossible to guard completely against the ability to "back calculate" and in the circumstances, this may be viewed as an acceptable risk.

2683. For these reasons, the ERA maintains it position from the draft decision and requires Western Power to comply with draft decision required amendment 75.

Required Amendment 60

Clause 24.9(d) of the applications and queuing policy must be amended in accordance with paragraph 2683 above of this final 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

2684. Synergy further submitted that proposed clause 6.2 of the applications and queuing policy would entitle Western Power to disclose confidential information set out in clause 24.9 in a non-anonymised basis if disclosure is necessary for the performance of Western Power's functions. Western Power's proposed changes to clause 6.2 was considered at paragraphs 2673 and 2674 (above) – the changes concerning disclosure of confidential information that is "necessary for the performance of Western Power's functions" was not approved.

2685. No submissions on Western Power's initial proposal addressed Western Power's proposal to insert new clause 24.10(a) to confirm that it can disclose the information in clause 24.9 when issuing notice of intentions, preliminary access offers and access offers.

2686. Updating information provided to applicants under proposed clause 24.10(a) is consistent with section 5.7(a) of the Access Code because it allows applicants to know (in advance) how the policy will apply to them and gives greater clarity as to the status of their application or preliminary offer.

Agreement between applicant and Western Power (ID 20)

2687. Western Power noted that the current applications and queuing policy only allows transfer applicants (and not connection applicants) to mutually agree to depart from the policy subject to no impediment to other applicants.

2688. Western Power submitted that:[679]

> Clause A2.101 of the Model AQP [in the Access Code] allows the service provider and an applicant to agree to deal with a matter in connection with an electricity transfer application or connection application in a manner different to that set out in the AQP

[679] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 22-23.

> so long as the service provider's ability to provide a covered service to another applicant is not impeded.
>
> Clause 7.4 of the [existing] AQP reflects this by allowing applicants to agree with Western Power to depart from the AQP in progressing an electricity transfer application, provided that doing so causes no impediment to other applicants. This clause is located within Part B of the AQP which only applies to electricity transfer applications.
>
> However, unlike the Model AQP, there is no equivalent provision in relation to connection applications in the AQP.
>
> This flexibility should also apply to connection applications. Western Power receives a number of requests for simple connections (e.g. households) which do not compete with other applications and which do not require the procedural rigour of the AQP to be satisfied.

2689. Western Power proposed to insert a new clause (2.2(d)) to allow it and applicants to agree to deal with any matters in connection with an electricity transfer application *or* connection application in a manner different to what is set out in the applications and queuing policy. Existing clause 7.4 of the policy was deleted:

> (d) An applicant and Western Power may agree to deal with any matter in connection with an application in a manner different to the treatment of the matter in this applications and queuing policy as long as the ability of Western Power to provide a covered service that is sought by another applicant is not impeded.

2690. Synergy considered proposed new clause 2.2(d) would allow Western Power and an applicant to agree to the different treatment of an application under the policy as long as the application was not a *competing application*. Synergy was concerned the approach could lead to a situation where applicants forego protections or provisions (which are in an applicant's best interests) to expedite arrangements.[680] It also considered the approach could result in the discriminatory treatment of applicants, given the relative bargaining power of an applicant and Western Power in such circumstances.

2691. Western Power's proposed new clause (2.2(d)) replicates section A2.10 of the model applications and queuing policy in the Access Code, which stated:

> A2.101 An applicant and the service provider may agree to deal with any matter in connection with the applicant's application in a manner different to the treatment of the matter in this applications and queuing policy as long as the ability of the service provider to provide a covered service that is sought by another applicant is not impeded.

2692. The term "application" under the model policy applies to both connection and transfer applications.

2693. The ERA has considered Synergy's submission and was of the view that the intention of the clause was to allow an applicant and Western Power to *agree* to treat any matters in connection with the applicant's application differently to what is required in the policy. It would be up to the applicant to decide whether or not it wanted to forego particular provisions and/or protections to expedite arrangements, and whether or not it accepted any perceived discriminatory treatment. Where the

[680] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 15, paragraphs 55 to 58.

applicant and Western Power cannot agree, the standard provisions of the policy would apply.

2694. Nevertheless, the proposed new clause replicated the same clause in the model applications and queuing policy and hence met the requirements for such a policy. This is consistent with section 5.11(a) of the Access Code, where the ERA:

> must determine that an applications and queuing policy is consistent with sections 5.7 to 5.9 and the Code objective to the extent that it reproduces without material omission or variation the model applications and queuing policy.

2695. Western Power's revised proposal does not readdress this matter and no further submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

Conditions precedent (ID 24)

2696. Western Power proposed to amend clause 4.8 as follows:

> 4.8 Conditions Precedent Not Longer Than 8 Months
>
> (a) Western Power and an applicant ~~may~~must not enter into an access contract that contains a condition precedent for which a period of longer than 8 months from the date the access contract was entered into is allowed for its fulfilment, unless a longer period is reasonably necessary, including due to the nature of works to be conducted.
>
> (b) If, after 8 months or such other period of time agreed under clause 4.8(a), a condition precedent in an access contract has not been fulfilled, then:
>
> (i) if there is no competing application, Western Power and the relevant user may agree within 20 business days to extend the period in the access contract allowed for the satisfaction of ~~conditions~~the condition precedent by up to a further 6 months; or
>
> (ii) if …

2697. Western Power considered the proposed amendments more accurately reflect the operation of the clause and that flexibility to allow for a longer period of time is required. It submitted:[681]

> Often conditions precedent in access contracts require the completion of works. In some cases, due to the nature of the works it is reasonable and necessary to have a period longer than 8 months for the completion of the works and therefore the satisfaction of the condition precedent.
>
> The [existing] AQP provides that Western Power and an applicant 'may not' (which in this context has the effect of 'must not') enter into an access contract containing a condition precedent with a period for satisfaction longer than 8 months. Additional flexibility is required to enable Western Power to agree to conditions precedent with a period for satisfaction longer than 8 months where reasonably necessary.

2698. No submissions on Western Power's initial proposal addressed these proposed amendments.

2699. In the draft decision, the ERA determined Western Power's proposed changes were consistent with the requirements of section 5.7(a) of the Access Code to accommodate the interests of users and applicants. However, the ERA considered:

[681] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 23.

- There should be a fixed upper limit on the period allowed in sub-clause (a).
- Further drafting amendments should be made to better link sub-clauses (a) and (b).

2700. The ERA required the following further amendments:

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:

2701. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 [paragraph 2700 above] to:

- set a fixed upper limit on the period allowed in sub-clause (a); and
- better link sub-clauses (a) and (b).

2702. In its revised proposal, Western Power accepts draft decision required amendment 76 in principle with modifications.[682]

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.

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.

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.

[682] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 251-252.

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.

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: …

2703. The ERA considers Western Power's proposed amendment is reasonable. The ERA agrees the upper limit of 12 months relating to works to be completed by Western Power may be insufficient and inflexible for large complex connection works and shared network works. The proposed amendments are reasonable and the ERA is satisfied that Western Power has complied with draft decision required amendment 76.

Proposed amendments to support "time of use" tariffs and advanced metering (ID 27 to 31)

2704. Western Power proposed to introduce Advanced Metering Infrastructure (**AMI**) and time of use tariffs for AA4. The ERA gave consideration to Western Power's proposal for AMI expenditure at paragraph 450 (and following) of its draft decision and time of use tariffs at paragraph 848 (and following).

2705. Based on its proposal for AMI and time of use tariffs, Western Power proposed a number of amendments to the applications and queuing policy comprising:[683]

- A new clause 10.1(f) to require a user to make an electricity transfer application to change the user's reference service if an AMI meter is installed at the user's connection point.
- Drafting changes to clause 14.1(c) to make the requirement for revenue meters applicable to AMI meters.
- Drafting changes to clause 8 to confirm that applications for a reference service made by an electricity transfer application are made under Part B of the policy and that clause 8 applies to all applications made under Part B.
- New subclauses to clause 3.6 to require the applicant to provide information about:
  - Its eligibility for the covered service sought (new clause 3.6(a)(iv)).
  - Any facilities and equipment likely or required to be connected at the connection point in circumstances where the application relates to a new connection point (new clause 3.6(b)(ii)(B)).

[683] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 27-28, Table 2.5.

- Consequential changes to insert and/or amend definitions under clause 2.1 of the policy, including a new definition for “AMI meter”.

2706. The ERA did approve the introduction of mandatory time of use tariffs or expenditure for advanced metering communication infrastructure. Consequently, the proposed changes to support mandatory time of use tariffs and advanced metering were not required and were not approved.

2707. The ERA’s draft decision required the following amendment to Western Power’s proposal.

> **Draft Decision 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.

2708. In its revised proposal, Western Power accepted draft decision required amendment 77 in principle with modifications.[684]

> 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.
>
> 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.
>
> 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.

2709. After considering the points made by Western Power, the ERA agrees the amendments to clauses 3.6(a)(iv) and 3.6(b)(ii)(B) are reasonable. The amendment to clause 8 is useful to clarify that the provision relates only to electricity transfer applications made under Part B of the AQP. The ERA is satisfied Western Power has complied with draft decision required amendment 77.

Other minor amendments to the policy

2710. Western Power proposed various other minor amendments to the applications and queuing policy as set out in Table 2.4 of Attachment 12.3 to the access arrangement information.[685] The ERA considered these amendments in turn below.

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[684] Western Power, Revised AA4 proposal: Response to the ERA’s draft decision, 14 June 2018, pp. 252-253.

[685] Western Power, *Access arrangement information: Attachment 12.3 [redacted]*, 2 October 2017, pp. 25-26, Table 2.4.

Notes to defined terms (minor amendments 1 and 2)

2711. Western Power either inserted or amended the "notes" that accompany the following definitions at clause 2.1 of the policy:

- access dispute
- customer transfer request
- generating plant
- loss factor
- market participant
- meter
- relocation
- revenue meter
- verifiable consent.

2712. Western Power proposed to change the definition of relocation as follows:

> **"relocation"** has the meaning given to ~~it~~'relocation' in the ~~Code~~transfer and relocation policy.
>
> {Note: under the transfer and relocation policy, 'relocation' has the meaning given to it in clause 6.1. That clause provides that a 'relocation' occurs when a user:
>
> (a) decreases its contracted capacity at a connection point (a "retiring point"); and
>
> (b) makes a corresponding increase in its contracted capacity at another connection point the user is entitled to use under its access contract (a "destination point")}

2713. While Western Power acknowledged the proposed definition of "relocation" in the applications and queuing policy and Access Code do differ, it considered there was no substantive difference between the definitions set out in the Access Code, transfer and relocation policy, or proposed applications and queuing policy that would lead to (or produce) any inconsistencies in practice.

2714. Synergy noted the different definitions of relocation in the proposed applications and queuing policy and Access Code[686], and Western Power's views. Synergy submitted that:[687]

> It is not open to WP (or the Authority) to establish definitions in regulatory documents forming part of an access arrangement that are not consistent with the intent set out in the Access Code. Further, clear alignment with the Access Code in matters such as defined terms is required for consistency and certainty. It is the Access Code (not the [transfer and relocations policy] or the AQP) that sets the requirements for the AQP (including what is meant by "relocation"). The Authority should reject WP's proposed amendment to the definition of "relocation" in the AQP and instead require the definition provided for in the Access Code.

---

[686] The Access Code defines *"relocation"* to mean *"a relocation of capacity from one connection point in a user's access contract to another connection point in the user's access contract under a transfer and relocation policy"*.

[687] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, pp. 14-15, paragraph 53.

2715. Amendments to the "notes" that accompany the defined terms listed in paragraph 2711 (above) were accepted because the amendments have been made to reflect changes to definitions in other legislative instruments.

2716. However, in line with Western Power's proposed changes to keep definitions in the applications and queuing policy consistent with other legislative instruments, the ERA considered the definition of "Customer Transfer Code" required amendment to refer to the *Electricity Industry Customer Transfer Code 2016*, which replaced the 2004 Code that the policy currently refers to.

2717. Western Power's proposed changes to the defined term "relocation" made it consistent with the definition of relocation in clause 6.1 of the transfer and relocation policy, which was not inconsistent with the definition in the Access Code.

2718. The ERA's draft decision required the following amendment to Western Power's proposal.

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).

2719. In its revised proposal, Western Power has accepted draft decision required amendment 78 and has made the required amendments to the definition of "Customer Transfer Code".[688]

2720. No submissions were received on the draft decision.

2721. The ERA is satisfied that Western Power has complied with draft decision required amendment 78.

Defined terms (minor amendment 3)

2722. Western Power inserted the defined term "final notice" to clause 2.1 of the applications and queuing policy, which had the meaning given in clause 20A.

2723. The ERA considered the proposed addition of the term "final notice" to be administrative in nature and necessary to reference the term defined in clause 20A.

Redundant terms (minor amendment 4)

2724. Western Power deleted the term "reserve capacity auction" from clause 2.1 of the applications and queuing policy because the term was no longer used.

Improving clarity (minor amendment 5)

2725. Western Power made several amendments to the applications and queuing policy for clarification. The definitions of "applicant-specific solution", "application form" and "competing applications group" were changed. Drafting amendments were also made to clause 17A.4(a)(ii).

[688] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 253.

2726. The ERA considered the proposed amendments were made for clarification purposes – the amendments clarified the policy and improved readability.

Order of defined terms (minor amendment 6)

2727. Western Power reordered the definitions of “contributions policy” and “connection point” so that the terms appeared in clause 2.1 in alphabetical order. This change was administrative in nature and corrected a formatting error.

Drafting improvements (minor amendment 7)

2728. Western Power made various drafting improvements throughout the applications and queuing policy, which it considered did not affect the substantive meaning of the relevant clauses. The amendments include changes to the definition of "connection application" and changes to clauses 3.6(b)(iii), 3.9(b), 3.13(b), 3.15(a), 3.15(b), 3.15(d) (regarding the insertion of the word "that'), 4.5, 4.8(b)(i), 7.2(a), 14.3(a), 24.2 (regarding the insertion of the words "to avoid doubt"), 24.3(b), 24.5(a), 24.5(b), 24.5(d), 24.6, 24A.3(d) and 26.

2729. The ERA considered the proposed amendments and was of the view that the majority of the amendments did improve the drafting of the policy and did not materially affect the intent of the relevant clause with the exception of:

- Clause 3.15(a) – the word “whether” was to be reinstated (and the proposed word “including” deleted). The original drafting was considered clearer.
- Clause 4.8(b)(i) – the words “conditions precedent” were to be reinstated because there may be more than one condition precedent in an access contract.
- Clause 24.3(b) – the drafting of this clause could have been improved by removing the word “to” to read: “advising that they do not wish to opt out of the competing applications group and make an application for an applicant-specific solution, in which case…”.
- Clause 24.5(a) – the word “after” was to be reinstated, which was consistent with the ERA’s considerations at paragraph 2483 of the draft decision.
- Clause 24.6 – the drafting of this clause could have been improved to clarify when the 30 business day timeframe starts by amending the clause as follows. The words “it will” was also be reinstated in clause 24.6(a) as follows:

> 24.6 Subsequent Access Offers
>
> After reviewing the responses by applicants to preliminary access offers under clause 24.5, Western Power will endeavour, within 30 business days from the last date on which responses are required~~of the expiry of the period under that clause for responses~~ to be provided to Western Power under clause 24.5, to complete the following:
>
> (a) if Western Power considers it can make access offers to applicants within the competing applications group collectively for the costs nominated in the access offers, it will make access offers to applicants within the competing applications group conditional on sufficient acceptance of the access offers by applicants to ensure that access can be provided to the applicants collectively for the costs nominated in the access offers; or

2730. The ERA’s draft decision required the following amendment to Western Power’s proposal.

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 [paragraph 2730 above].

2731. In its revised proposal, Western Power has accepted draft decision required amendment 79 in principle with modifications.[689]

> 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.
>
> - Clause 3.15(a) – we do not accept the required amendment to reinstate the word *'whether'* in place of *'including'*.
>
>   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.
>
>   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.
>
> - Clause 4.8(b)(i) – we do not accept the ERA's proposed change to reinstate '*conditions precedent'.*
>
>   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.
>
> - Clause 24.3(b) – we accept the deletion of *'to'*.
>
>   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.
>
> - Clause 24.5(a) – we accept the required amendment.
>
> - Clause 24.6 – we accept the required amendment to clause 24.6, but suggest that the words '*it will'* are also added to clause 24.6(b) for consistency.

[689] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 253-254.

2732. No submissions from third parties on the draft decision were received.

2733. The ERA is satisfied that Western Power's proposed modifications address draft decision required amendment 79 for the following reasons.

- In clause 3.15(a), the ERA agrees the term "whether" is not appropriate as it suggests that all applications under the AQP have to be processed as either applicant specific solutions or within competing applications groups, which is incorrect. Using the word "including" or deleting all text within and including the parenthesis is appropriate.
- In clause 4.8(b)(i), the ERA agrees clause 4.8(a) appears to relate to a single condition precedent such that clause 4.8(b)(i) should be restricted to a single condition precedent also, recognising that whilst parties may agree to extend one condition precedent, that does not effectively extend all other conditions precedent.
- In clause 24.3(b), the ERA agrees that the words "do not" are a drafting error and should not be included.
- In clause 24.6, the ERA agrees that adding the words "it will" to clause 24.6(b) is appropriate and consistent with the amendment made to clause 24.6(a).

Grammar and formatting (minor amendments 8 and 9)

2734. Western Power made punctuation and cross-referencing changes throughout the applications and queuing policy (see for example clauses 3.6(b), 3.10(d) and 3.11(c)). These amendments were considered administrative in nature and did not affect the substantive meaning of the relevant clauses.

Statutory terminology (minor amendment 10)

2735. Western Power amended clause 5.4(b) to remove the word "stamp" before "duty" to reflect changes in the statutory terminology regarding duty. The amendment reflected current statutory terminology.

Process overview (minor amendments 11 and 12)

2736. The current applications and queuing policy includes a figure in clause 1.1 that illustrates how the policy operates. Western Power proposed to amend the clause to remove the figure and replace clause 1.1 with new drafting that refer to the appendices of the policy:

> 1.1 Operation of this Applications and Queueing Policy
>
> ~~This applications and queuing policy operates in the manner shown in Figure 1 (next page).~~
>
> 1.1 Status of Appendices
>
> Appendix A and Appendix B contain additional explanatory material regarding information provided to applicants and the processes contemplated by this applications and queuing policy. To avoid doubt, Appendix A and Appendix B are included for explanatory purposes and do not form part of the operative provisions of this applications and queuing policy.

2737. The proposed changes made to the appendices (A and B) are summarised below:

- Appendix A – Competing Applications Group Process Description

- A reference to Figure 1 was deleted, along with tables outlining what primary information Western Power will provide to applicants and how the competing applications group will be managed.

- Appendix B – Timelines for Applicant-specific Solutions and for Competing Applications Group

  - An additional action item (for Western Power to issue a preliminary access offer) was added to the timeline for the competing applications group process.

  - *"Studies, design and cost estimates for the solution"* were added to the list of variable components that may affect the timeframes.

2738. Western Power submitted that the proposed changes to clause 1.1 and appendices A and B of the applications and queuing policy:[690]

- Did not detract from the rights and obligations of parties under the policy.

- Provided additional explanation about the processes under the policy.

- Clarified that the appendices did not form part of the operative provisions of the policy and are for explanatory purposes only.

2739. No submissions on Western Power's initial proposal addressed the proposed changes outlined above. However, section 3.3 of Western Power's Attachment 12.3 to the access arrangement information indicated that stakeholders raised concerns about the proposed changes during Western Power's stakeholder engagement sessions.[691]

2740. The stakeholder engagement feedback indicated that:

- Stakeholders were not convinced about Western Power's justification for removing the detailed process overview (Figure 1) from the applications and queuing policy.

- The "high level steps" process diagram in Appendix A to the applications and queuing policy was neither binding nor detailed enough to disclose to applicants the true process Western Power was proposing under the policy.

- A detailed process overview, as a binding part of the applications and queuing policy, is a valuable explanatory tool that is consistent with section 5.7(b) of the Access Code.

- The detailed process overview (Figure 1) should be retained with amendments made, if required, to remove the complexity that Western Power cited as a reason to remove the figure from the policy.

2741. Western Power responded to the stakeholder feedback with the following comments:

- Figure 1 did not enhance the policy nor did it add to its written provisions. The removal of Figure 1 would also not detract from the rights and obligations of parties under the policy.

- Figure 1 was intended to be illustrative only and readers of the policy were to have regard to the written provisions in understanding the rights and

[690] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, p. 26.

[691] Western Power, *Access arrangement information: Attachment 12.3 [redacted],* 2 October 2017, pp. 54-56.

obligations of parties under the policy. If an issue were to arise under, parties would rely on the written provisions of the policy, not Figure 1.

- The Access Code does not require the policy to contain a ‘process overview’ diagram. The written provisions of the policy satisfied the requirements of the Access Code for the policy to be sufficiently detailed to enable users and applicants to understand in how advance how the policy operates.
- Since AA3 was introduced, Figure 1 was not used in discussions with applicants, and hence, the figure was of no practical value. Figure 1 may have actually confused applicants.

2742. Given the complexities of the current applications and queuing policy, particularly the processes for competing applications groups, the ERA considered a flowchart setting out the entire process was necessary to enable users to understand how the policy operates. This understanding was supplemented by the tables listing the information Western Power was to provide to applicants during the process and how the competing applications group could be managed. Based on the feedback provided during Western Power’s stakeholder engagement sessions, the information appeared to be valued by stakeholders.

2743. The ERA considered that Figure 1 and the tables outlining the primary information Western Power would provide to applicants and how the competing applications group would be managed, were necessary to meet the requirements of section 5.7(b) and 5.7(e) of the Access Code. If necessary, Western Power was to amend Figure 1 and the primary information tables to ensured consistency with the policy, enhanced understanding of the process and removed any unnecessary complexities or confusion. Information on the generators interim access solution process was also to be included.

2744. The ERA’s draft decision required the following amendment to Western Power’s proposal.

Draft Decision Required Amendment 80

The applications and queuing policy must retain Figure 1 (“Access, Connection and Transfer Applications Policy – Process Overview”).

2745. In its revised proposal, Western Power has accepted draft decision required amendment in principle with modifications.[692]

> 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.
>
> 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.

[692] Western Power, Revised AA4 proposal: Response to the ERA’s draft decision, 14 June 2018, pp. 254-255.

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.

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.

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.

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.

2746. The ERA does not accept the arguments put forward by Western Power. An accurate flow chart and tables setting out the timelines and documents for each part of the process is necessary to assist applicants to follow the process.

Required Amendment 61

Western Power must retain Figure 1 ("Access, Connection and Transfer Applications Policy – Process Overview") and the tables headed "Primary Information provided to applicants by Western Power" and "How the Competing Applications Groups (CAGs) will be managed." Western Power must ensure the information in the flowchart and tables is consistent with the relevant clauses of the applications and queuing policy.

Suppliers of last resort and default suppliers

2747. Section 5.7(g) of the Access Code requires that an applications and queuing policy must establish arrangements to enable a user who is a:

- "Supplier of last resort" as defined in section 67 of the *Electricity Industry Act 2004* to comply with its obligations under Part 5 of the Act.
- "Default supplier" under regulations made in respect of section 59 of the *Electricity Industry Act 2004* to comply with its obligations under section 59 of the Act and the regulations.

2748. Clause 24A.5 of the current applications and queuing policy specifies that priority must be given to applications to the extent necessary to enable a supplier of last resort or default supplier to meet its obligations. No amendments were proposed for this clause and no submissions made to the ERA raised concerns regarding these provisions. On that basis, the ERA considered the clause continued to meet the requirements of section 5.7(g) of the Access Code.

Facilitation of Part 9 of the Act

2749. Section 5.7(h) of the Access Code requires that an applications and queuing policy must facilitate the operation of Part 9 of the *Electricity Industry Act 2004*, any enactment under Part 9 of the Act and the “market rules” as defined in section 121(1) of the Act.

2750. Part 9 of the Act deals with establishing a wholesale electricity market and provides the head of power for the Market Rules. Section 7.7(h) requires, in practical terms, that the applications and queuing policy facilitate the operation of the wholesale electricity market.

2751. In its final decision for AA3 the ERA noted:

> … any deficiencies of the wholesale electricity market and reserve capacity mechanism cannot be fully resolved through the queuing rules in the applications and queuing policy. As noted in the ERA’s final decision for [AA2], this requires consideration in a broader review of regulatory arrangements for the electricity market that considers network planning processes, the functioning of the wholesale electricity market, the treatment of new investment under the Access Code, as well as the [applications and queuing policy].

2752. The ERA considers this still to be the case. For example, as raised in stakeholder submissions, Western Australia’s current wholesale electricity market design places restrictions on Western Power’s ability to connect new generation.

Other matters raised in submissions about the policy

Information required with all applications

2753. Clause 3.5 of the applications and queuing policy details the information that must be provided by applicants to Western Power when making an application. Western Power did not propose any amendments to this clause.

2754. Mr Stephen Davidson submitted that the requirements of the existing clause were inconsistent with the data requirements of the Technical Rules (for example, the facility’s minimum load is not included). The full schedules contained in the Technical Rules were to be included in the requirements of clause 3.5 for loads and generators (if on-site generation is present). Mr Davidson submitted:[693]

> The proposed is a shortcut that would amount to, effectively, having no paperwork in place. A similar practice of taking shortcuts in the banking sector (low documentation loans) have been detrimentally affecting customers. I do not believe that low documentation access applications will be beneficial for any business activity, including engineering, legal, commercial, financial, regulatory and auditing.
>
> Residential and small business customers will be best protected from the rising electricity prices by a paper trial of the full set of the access application information data stipulated in the Technical Rules. The process will be more straightforward, efficient and there would be no need for the Western Power to assume the data not supplied by the applicant. The applicant must be responsible for own plant (on site load and generation) data supplied to the WP, and the WP must be responsible for the network data supplied to the applicant.

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[693] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24),* 11 December 2017, Issue 24.

> [Clause] 3.5(d) Include the full schedules of the [technical rules] into the requirements of section 3.5, as it is not appropriate for Western Power to have discretionary power to choose which data to request from different applicants.

2755. The ERA considered that the purpose of clause 3.5 was to require applicants to provide only the necessary information needed for Western Power to conduct a *preliminary assessment* of an application. If any further information was required, Western Power could request additional information under clause 3.11 of the policy. For connection applications, more extensive information was to be provided by the applicant under clause 3.7(e) that concerns the facilities and equipment at the connection point "to the extent required by the technical rules; and Western Power acting as a reasonable and prudent person". Given these provisions, the ERA considered it was not necessary to require applicants to provide additional information beyond what is currently required in clause 3.5.

2756. No further submissions were received on this matter in response to the draft decision.

Electricity transfer application for a new connection point

2757. Clause 9 of the applications and queuing policy is titled "electricity transfer application for a new connection point" and contains two sub-clauses:

- clause 9.1 – customer transfer request
- clause 9.2 – creating a new connection point or connecting new generating plant

2758. Mr Stephen Davidson submitted that sub-clause 9.2 should read "creating a new connection point" (that is, the words "or connecting new generation plant" should be deleted).[694]

2759. The ERA considered the title for sub-clause 9.2 reflected the subject matter of the clause as clause 9.2(a) applies to applicants who seek to create a new connection *or* to install new generation plant at an existing connection point.

2760. No further submissions were received on this matter in response to the draft decision.

Increase or decrease in contracted capacity

2761. Clause 10.2 of the applications and queuing policy details provisions concerning the increase or decrease in contracted capacity.

2762. Mr Stephen Davison submitted that clause 10.2 should be modified as follows.[695]

> Modify the clause to the effect that a new access application is required, and that the applicant must provide the full set of data as required in the Technical Rules.
>
> Time period of 5 days is unfair to Western Power engineers, it puts unnecessary pressure to quickly make unreasonable decisions. 5 days should be sufficient to check if the application is complete.

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[694] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24)*, 11 December 2017, Issue 24.

[695] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24)*, 11 December 2017, Issue 24.

2763. If Western Power determined that it cannot make a decision about increasing or decreasing an applicant's contracted capacity, it can request the applicant, under clause 10.2(e), to submit a connection application.

2764. Clause 10.2(c) requires Western Power to notify the applicant of whether or not it accepts the increase or decrease in contracted capacity within five business days of receiving the applicant's notice to change its contracted capacity, "or such further time as a prudent service provider would reasonably require to consider such [an] application". Given Western Power did not propose any changes to clause 10.2(c), it is assumed that the five business day timeframe was reasonable for it and its engineering staff. In any case, there is an allowance for Western Power to take additional time in circumstances where it is reasonably required.

2765. No further submissions were received on this matter in response to the draft decision.

More than one change or modification within 12 months

2766. Synergy submitted that it experienced operational difficulties with the provisions of clause 10.3(c) and requested the following changes:

> If Western Power receives:
>
> (a) more than 1 application or notice under clause 10.1; 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~~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:
>
> (i) a change …

2767. In support of its proposal, Synergy submitted the following information:[696]

> In the past, WP has only permitted Synergy to change the covered service in relation to a connection point once in a 12 month period. WP has rejected any additional application Synergy has made even though the reason for the change is consistent with clause 10.3(c) of the AQP. WP's proposal is therefore inconsistent with sections 5.7(a), 5.7(b) and 5.7(c) of the Access Code. For example:
>
> - A customer on an anytime energy tariff will seek a time-of-use tariff from Synergy.
> - Synergy will change the network service to a time-of-use service and WP will approve this change.
> - The customer, within a 12 month period, may purchase a PV system and Synergy will apply to WP to change the network service to a bi-directional service. However, in this case WP will reject the change but will approve the connection of the PV system.
>
> Synergy notes the Authority's obligation under section 26 of the ERA Act to have regard to the need to promote competitive and fair market conduct and the need to

[696] Synergy, *AA4 Submission Number 3: Western Power's proposed application and queuing policy*, 8 December 2017, p. 19, paragraphs 76 and 77.

prevent abuse of monopoly or market power. Synergy submits that clause 10.3(c) of the AQP must be amended to be consistent with both section 5.7(b) of the Access Code (that is, allowing users to understand in advance how the AQP will operate) and the Access Code objective to promote competition in markets upstream and downstream of the networks – for example competition in the provision of battery, photovoltaic systems (PVs) and electric vehicles (EVs).

2768. In the draft decision, Synergy's proposed amendment was considered consistent with section 26 of the *Economic Regulation Authority Act 2003* and the Access Code objective for the reasons set out in its submission (and reproduced above). Synergy also provided a real example of why the change was needed. The ERA agreed that clause 10.3(c) was to be amended 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, and is required for one of the circumstances listed in clauses 10.3(c)(i) to (vii).

2769. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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:"

2770. In its revised proposal, Western Power has not accepted draft decision required amendment 81 and has instead proposed further amendments to clause 10.3.[697]

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.

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

[697] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 255-257.

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.

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*.

2771. For the reasons given in the draft decision, the amendments proposed by Western Power are not consistent with section 26 of the *Economic Regulation Authority Act 2003* or the Access Code objective, with the exception of Western Power's proposal to reinsert "as a reasonable and prudent person", which the ERA considers is reasonable and consistent with other parts of the access arrangement and accepts this proposal. The other proposed changes in Western Power's revised proposal are not accepted.

Required Amendment 62

Western Power must comply with draft decision required amendment 81 with the insertion of “as a reasonable person” as set out in paragraph 2771 above.

Reporting during the processing of the connection application

2772. Mr Stephen Davidson submitted that existing clause 19.3(d) should be deleted from the applications and queuing policy because such a decision cannot be made without conducting proper power system studies.

2773. Western Power did not propose any amendments to clause 19.3(d) of the policy. The existing clause states:

> A preliminary assessment with regards to a connection application may consist of an assessment as to:
>
> …
>
> (d) if it is likely that works will be required — a good faith estimate of the likely time required for the planning, designing, approving, financing, construction and commissioning, as applicable, of any necessary augmentation or works; and

2774. In the draft decision, clause 19.3(d) of the applications and queuing policy was considered consistent with clause A2.93(c) of the model applications and queuing policy in the Access Code, which requires the service provider to give the applicant a preliminary assessment that includes “a good faith estimate of the likely time required for the undertaking of any required work”.

2775. As clause 19.3(d) of Western Power’s applications and queuing policy had materially reproduced clause A2.93(c) of the model policy it was to be retained. The clause was considered reasonable as it only requires an estimate of likely time required, which Western Power’s past experience enables it to do.

2776. No further submissions were received on this matter in response to the draft decision.

Connection application costs

2777. Clause 20 of the applications and queuing policy details provisions for connection application costs and includes the following sub-clauses:

- clause 20.1 – applicant must pay costs
- clause 20.2 – processing proposal
- clause 20.3 – applicant-specific solution option
- clause 20.3A – interaction between applicant-specific solutions and competing applications groups
- clause 20.4 – disputes may be referred to arbitrator

- clause 20.5 – use of engineering firms to provide studies

2778. Mr Stephen Davidson submitted that the clause is inconsistent with the consumer protection regime in Australia.[698]

> The proposed is inconsistent with the Consumer Protection regime in Australia. Western Power should provide the Scope of Works (SOW) for power system studies and let the Applicant decide who will conduct the work, unless Western Power does the studies free of charge. Western Power should not demand forced trading.

2779. Mr Davidson further submitted that:

- the technical and commercial matters are mixed up in clause 20.2
- the provisions in clause 20.5 are anti-competitive, forced trading; not transparent and open ended.

2780. Clause 20 was consistent with clauses A2.13 to A2.19 of the model applications and queuing policy in the Access Code and, therefore, must be accepted. Clause A2.13 provided that an applicant must pay reasonable costs to process the application. It was therefore not unreasonable to require the applicant to pay for any costs reasonably incurred by Western Power for studies and cost estimates agreed with the applicant under clauses 20.2 and 20.3 of the applications and queuing policy.

2781. Clause 20.2 sets out provisions for processing a proposal, which are considered standard provisions for a policy of this nature. In the draft decision the ERA was not able to identify any problems with the clause.

2782. The ERA considered clause 20.5 is to the applicant's benefit as it allows the applicant to request that an engineering firm conduct the studies as required under the policy. This gives the applicant the ability to satisfy itself that any studies conducted for its application are unbiased. This is consistent with clause 5.7 of the Access Code as it accommodates the interests of both the service provider and applicant.

2783. Mr Davidson's response to the draft decision puts forward the following suggested amendments to clauses 18.2, 20.2 and 20.5:

> (a) Western Power has obligation to provide to the applicant a scope of work (SOW) for preliminary connection application power system studies and works. The SOW must include data requirements and obligations, for example, the list of data to be provided by the: a) applicant, and b) Western Power.
>
> (b) The applicant has right to choose an engineering firm to carry out preliminary connection application power system studies and works stipulated in clause 20.2(a).

2784. Clause 18.2(c) states that clause 20 applies so the comments below are also relevant for clause 18.2.

2785. If Western Power considers it must perform any system or other studies then clause 20.2(a)(i) requires it to provide a proposal to the applicant outlining the scope, timing and a good faith estimate of the likely costs to be incurred for processing the connection application and/or others undertaking the studies, cost estimates or other works.

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[698] Stephen Davidson, *Submission (Comments on Issue 23 and Issue 24)*, 11 December 2017, Issue 24.

2786. Under clause 20.5 an applicant may ask Western Power to permit an engineering firm to undertake a system or other study under clause 20. Western Power must not unreasonably agree to such a request and, if it does disagree, must provide written reasons explaining why it has disagreed.

2787. The ERA considers the matters raised by Mr Davidson in paragraph 2783 are adequately dealt with in the applications and queuing policy.

CONTRIBUTIONS POLICY

Access Code requirements

2788. The contributions policy sets out the principles and processes for determining when a contribution will be required from a user, including for a network augmentation, and for determining the amount of the contribution.

2789. A "contribution" is defined in section 1.3 of the *Electricity Networks Access Code 2004* (Access Code) as a capital contribution, a non-capital contribution or a headworks charge.

2790. Section 5.1(h) of the Access Code requires that an access arrangement include a contributions policy, defined in section 1.3 of the Access Code as a policy in an access arrangement under section 5.1(h) dealing with contributions by users.

2791. The particular requirements for a contributions policy are set out in sections 5.12 to 5.17 of the Access Code:

Contributions policy

5.12 The objectives for a contributions policy must be that:

(a) it strikes a balance between the interests of:

(i) contributing users; and

(ii) other users; and

(iii) consumers;

and

(b) it does not constitute an inappropriate barrier to entry.

5.13 A contributions policy must facilitate the operation of this Code, including:

(a) sections 2.10 to 2.12; and

(b) the test in section 6.51A; and

(ba) sections 5.14 and 5.17D; and

(c) the regulatory test.

5.14 Subject to section 5.17A and a headworks scheme, a contributions policy:

(a) must not require a user to make a contribution in respect of any part of new facilities investment which meets the new facilities investment test; and

(b) must not require a user to make a contribution in respect of any part of non-capital costs which would not be incurred by a service provider efficiently minimising costs; and

(c) may only require a user to make a contribution in respect of required work; and

(d) without limiting sections 5.14(a) and 5.14(b), must contain a mechanism designed to ensure that there is no double recovery of new facilities investment or non-capital costs.

5.15 A contributions policy must set out:

(a) the circumstances in which a contributing user may be required to make a contribution; and

(b) the method for calculating any contribution a contributing user may be required to make; and

(c) for any contribution:

(i) the terms on which a contributing user must make the contribution; or

(ii) a description of how the terms on which a contributing user must make the contribution are to be determined.

5.16 A contributions policy may:

(a) be based in whole or in part upon the model contributions policy, in which case, to the extent that it is based on the model contributions policy, any matter which in the model contributions policy is left to be completed in the access arrangement, must be completed in a manner consistent with:

(i) any instructions in relation to the matter contained in the model contributions policy; and

(ii) sections 5.12 to 5.15; and

(iii) the Code objective;

and

(b) be formulated without any reference to the model contributions policy and is not required to reproduce, in whole or in part, the model contributions policy.

5.17 The Authority:

(a) must determine that a contributions policy is consistent with sections 5.12 to 5.15 and the Code objective to the extent that it reproduces without material omission or variation the model contributions policy; and

(b) otherwise must have regard to the model contributions policy in determining whether the contributions policy is consistent with sections 5.12 to 5.15 and the Code objective.

Contributions for certain Western Power Network work

5.17A Despite section 5.14, Electricity Networks Corporation may require a contribution for *Appendix 8* work of up to the maximum amount determined under Appendix 8 for the relevant type of *Appendix 8 work*.

5.17B From 1 July 2007 until the first revisions commencement date for the Western Power Network access arrangement, section 5.17A prevails over any inconsistent provisions of the Western Power Network access arrangement.

Headworks scheme

5.17C Despite section 5.14, the Authority may approve a contributions policy that includes a “headworks scheme” which requires a user to make a payment to the service provider in respect of the user’s capacity at a connection point on a distribution system because the user is a member of a class, whether or not there is any required work in respect of the user.

5.17D A headworks scheme must:

(a) identify the class of works in respect of which the scheme applies, which must not include any works on a transmission system or any works which effect a geographic extension of a network; and

(b) not seek to recover headworks charges in an access arrangement period which in aggregate exceeds 1 per cent of the distribution system target revenue for the access arrangement period; and

(c) identify the class of users who must make a payment under the scheme; and

(d) set out the method for calculating the headworks charge, which method:

(i) must have the objective that headworks charges under the headworks scheme will, in the long term, and when applied across all users in the class referred to in section 5.17D(c), recover no more than the service provider's costs (such as would be incurred by a service provider efficiently minimising costs) of any headworks; and

(ii) must have the objective that the headworks charge payable by one user will differ from that payable by another user as a result of material differences in the users' capacities and the locations of their connection points, unless the Authority considers that a different approach would better achieve the Code objective; and

(iii) may use estimates and forecasts (including long term estimates and forecasts) of loads and costs; and

(iv) must contain a mechanism designed to ensure that there is no double recovery of costs in all the circumstances, including the manner of calculation of other contributions and tariffs; and

(v) may exclude a rebate mechanism (of the type contemplated by clauses A4.13(d) or A4.14(c)(ii) of Appendix 4) and may exclude a mechanism for retrospective adjustments to account for the difference between forecast and actual values.

Current access arrangement

2792. The contributions policy is contained in Appendix C of the current access arrangement. It comprises three documents:

- Contributions policy (Appendix C.1)
- Distribution headworks methodology (Appendix C.2)
- Distribution low voltage connection headworks scheme methodology (Appendix C.3)

2793. The contributions policy applies if it is necessary for Western Power to perform certain works to provide covered services. "Works" is defined in the policy to include:[699]

> distribution headworks and distribution low voltage connection headworks scheme works and all works required to be undertaken to provide an applicant with the covered services sought by the applicant in a connection application, including works associated with:
>
> (a) augmentation of connection assets;
>
> (b) augmentation of shared assets;
>
> (c) alternative options; and
>
> (d) other non-capital works.

2794. Distribution headworks covers enhancements required to the existing high voltage three-phase distribution system that provides for an increase in capacity of that system. The distribution headworks methodology applies if Western Power

[699] Western Power, Amended proposed revision to the Access Arrangement for the Western Power Network: Appendix C.1 (Contributions Policy), June 2015, p. 11.

considers the forecast costs of distribution headworks required for a relevant area over a 25 year period exceeds the amount of new revenue likely to be gained from providing covered services to applicants over that period and:

- The relevant connection point is less than 160 kilometres (km) from a zone substation and the nominated capacity is less than 2,000 kilo-volt-ampere (kVA).
- or
- The relevant connection point is greater than 160 km from the zone substation and the nominated capacity is less than 1,000 kVA.[700]

2795. The distribution low voltage connection headworks scheme methodology was proposed and approved as part of the third access arrangement (AA3) review. It applies to upgrades to power supply in rural and regional areas situated 25 km or more from the nearest Western Power substation. The scheme allows the cost of infrastructure required for connection upgrades to be shared more evenly by all customers using the installed network. Charges are based on requested capacity, rather than whether or not the current network needs to expand because of the upgrade application.[701]

Western Power's initial proposal

2796. The contributions policy is included at Appendix C of the proposed access arrangement, and comprises two documents: the contributions policy (Appendix C.1) and the distribution low voltage connection scheme methodology (Appendix C.2).

2797. Western Power proposed changes to the contributions policy to improve clarity and accessibility. The proposed changes were set out in Attachment 12.4[702] to the initial access arrangement information and in marked-up versions of the documents provided with the initial proposal (Appendix C of the access arrangement).

2798. The proposed amendments to the contributions policy included:

- Changes to security provisions to assist customers in understanding when, and for how long, security may be held by Western Power.
- Introducing a 15-year revenue offset for residential customers connecting to the network to bring residential customers into line with commercial customers (who are already eligible for an offset of up to 15 years depending on the nature of the commercial project).
- Deleting the distribution headworks scheme from the contributions policy.
- Expanding the distribution low voltage connection headworks scheme to include all new capacity connections (but to exclude the connection of gifted assets).

[700] Western Power, Amended proposed revision to the Access Arrangement for the Western Power Network: Appendix C.1 (Contributions Policy), June 2015, clause 6.

[701] Western Power, Access arrangement information, 2 October 2017, p. 269, section 12.3.3.

[702] Contributions Policy for AA4 Change Summary.

Submissions on Western Power's initial proposal

2799. Submissions on Western Power's initial proposal from CdL Advisory, Community Electricity and the Western Australian Local Government Association (WALGA) addressed the contributions policy.

2800. CdL Advisory's submission questioned Western Power's forecasting of capital contributions for works under the State Underground Power Program (SUPP):[703]

> Issue 25: Contributions policy
>
> How does the following statement on page [183] of Western Power's Access Arrangement Information report correlate with the changes in criteria for Round 6 of the SUPP whereby a larger percentage of contributions (above 50%) from local councils (and their ratepayers) was considered for the first time in project selection?
>
> Western Power assumes a 54 per cent contribution rate for distribution customer driven works. This reflects the AA3 average recovery rate for contributions for the SUPP program.
>
> How does it also reflect the findings by the ERA in 2011 that 'Western Power should contribute an amount equal to its avoided costs when a particular project area is undergrounded (on average between 15 and 35 per cent but could be more or less than this).'

2801. Community Electricity supported Western Power's proposal to amend the contributions policy to expand the revenue offset provision to include residential customers:[704]

> Contribution policy - revenue offset for residential customers
>
> We note that in assessing the initial capital contributions payable by commercial users for connecting to the network, Western Power offsets 15 years' of usage payments to reduce the amount. Western Power is now proposing to apply that same discount to residential customers in order to make the initial cost of connection "...more affordable for more people".
>
> We support this initiative as being self-evident. We welcome that Western Power has eventually been compelled to this realisation and note that they successfully resisted it for a decade. We cite this as evidence of Western Power's culture that end-users are parasites to be deterred from accessing the network. We suggest that the motive behind their new insight is the realisation that customers now [have] the choice of whether to connect and can no longer be sustainably gouged.

2802. WALGA was concerned with the approach used to recover tax on gifted assets and asset relocations. WALGA submitted that local governments were affected because "it is common for local governments to make capital contributions to utility infrastructure providers as a result of asset relocations, which are required when local governments seek to improve the safety or efficiency of the road network through installation of roundabouts, traffic signals, turning lanes or road widening".[705] While it supported the use of upfront charges for new developments, it did not support the tax costs from capital contributions being recovered from the entity making the contribution:

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[703] CdL Advisory, *Submission on proposed revisions to the Western Power Network Access Arrangement*, 4 December 2017, p. 4, Issue 25.

[704] Community Electricity, *Response to ERA Public Consultation*, 10 December 2017, p. 5.

[705] WALGA, Submission to the Economic Regulation Authority, December 2017, pp. 11-12.

> Generally, [WALGA] supports the use of upfront charges for the costs of infrastructure built specifically for new developments. This ensures the application of the user pays principle and the achievement of efficient outcomes since development proponents will choose the most cost-effective areas for development.
>
> However, [WALGA] does not support the tax costs resulting from capital contributions being recovered from the entities that make such contributions. In doing so, the entire incidence of the tax is borne by these entities and their customers. This is not necessarily an efficient outcome and is likely to have significant distortions on activity.

2803. WALGA concluded that:[706]

- The current approach to tax recovery on gifted assets and relocations means that the entire incidence of the tax is borne by a single entity, and can have significant distortionary effects.
- For Local Governments, the viability of projects with significant public benefits, such as street lighting upgrades and asset relocations (particularly those that are initiated as a result of road safety upgrades), is affected by the inclusion of tax recovery costs.
- WALGA supports recovering the tax liability as a cost of business from all customers.
- The ERA should examine the merits of adopting the same approach used in the AER jurisdictions.

Considerations of the ERA

2804. The ERA considered the proposed changes to the contributions policy in the order in which they appear. The ERA also considered whether, in view of practical experience and submissions, the provisions of the contributions policy that remain unchanged are still consistent with the requirements of the Access Code.

Contributions policy

Definitions

2805. In its initial proposal Western Power proposed to delete some defined terms from clause 1.1 (definitions) of the contributions policy. The deletions are consequential to Western Power's proposal to delete the headworks scheme (existing clause 6) from the policy, which is addressed at paragraph 2828 below.

Provision of security for new revenue

2806. In its initial proposal Western Power redrafted the security provisions in the contributions policy (at clause 4.3) to assist connecting customers to better understand when, and for how long, security may be held by Western Power.[707] The proposed redrafting was as follows:

> 4.3 Applicant Must Provide Security for New Revenue
>
> <u>For the purposes of this clause 4.3:</u>
>
> <u>"estimated new revenue" means the amount calculated under clause 5.2(d).</u>

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[706] WALGA, Submission to the Economic Regulation Authority, December 2017, p. 13.

[707] Western Power, *Access arrangement information: Attachment 12.4,* 2 October 2017, p. 2.

“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 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 an unconditional, irrevocable bank guarantee 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 for the reduced amount, or

   (iii) has crystallised (such that some or all of the estimated new revenue will not be recovered), 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.

~~(a) Where the forecast costs with respect to a connection application are greater than $50,000, but less than $15,000,000, Western Power may require the applicant to procure before the commencement of the works, and maintain for a period of 18 months after the commencement of the associated exit service, entry service, or bidirectional service, an unconditional, irrevocable bank guarantee, or equivalent financial instrument, in terms acceptable to Western Power (acting as a reasonable and prudent person), guaranteeing the portion of new revenue that was used to calculate the contribution and is expected to come from providing an exit service, entry service, or bidirectional service using the works.~~

~~(b) Where an applicant has provided security under clause 4.3(a), then after 12 months, Western Power may:~~

   ~~(i) re-determine the contribution under this contributions policy, and recover from, or rebate to, the applicant any difference from the amount of the original contribution; or~~

   ~~(ii) require the applicant to maintain the bank guarantee or equivalent financial instrument for a further 12 months before re-determining the contribution in accordance with clause 4.3(b)(i).~~

~~(c) Where the forecast costs with respect to a connection application are equal to or greater than $15,000,000, Western Power may require the applicant to procure before the commencement of the works, an unconditional, irrevocable bank guarantee, or equivalent financial instrument, in terms~~

~~acceptable to Western Power (acting as a reasonable and prudent person), guaranteeing the portion of new revenue that was used to calculate the contribution and is expected to come from providing an exit service, entry service, or bidirectional service, using the works.~~

2807. No submissions on Western Power's initial proposal commented on the proposed changes to clause 4.3.

2808. In the draft decision the ERA determined that the proposed changes were consistent with the requirements of the Access Code. The ERA agreed with Western Power that the proposed changes assisted connecting customers to better understand their security obligations. The ERA required additional minor amendments to this clause to add further clarity and to make the terminology consistent:

For the purposes of this clause 4.3:

...

(a) Western Power may require an applicant to provide 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.

2809. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 [paragraph 2808 above] to add further clarity and to make the terminology consistent throughout the policy.

2810. In its revised proposal, Western Power has accepted draft decision required amendment 82 with some modified drafting.[708]

2811. No submissions were received on the ERA's draft decision.

2812. The ERA is satisfied Western Power has complied with draft decision required amendment 82. However, the "a" before "security" in clauses 4.3(a) and 4.3(c) should be deleted.

Required Amendment 63

The "a" before "security" in clauses 4.3(a) and 4.3(c) of the Contributions Policy must be deleted.

Revenue offset for residential customers

2813. In its initial proposal Western Power proposed to expand the contributions policy to make the provision of revenue offset available to residential customers. This would result in Western Power estimating the amount of incremental revenue from a new residential connection over a 15-year period and deducting this amount from the upfront capital contribution payable by the customer(s). Western Power stated the change to include residential customers:[709]

- Brings residential customers into line with commercial customers, who are already eligible for an offset of up to 15 years, depending on the nature of the commercial project.
- Recognises that residential customers making a new connection to the distribution network will incrementally contribute to Western power's network tariff revenues over time.
- Makes the initial cost of connection for residential customers more affordable by lowering the upfront costs that are payable at the time of connection.
- Provides greater alignment with policies mandated in other Australian jurisdictions under the national regulatory framework.

2814. Western Power considered the change, to include revenue offset for residential customers, "can be given effect without any specific wording change within the contributions policy".[710]

2815. As indicated above (at paragraph 2801) Community Electricity supported Western Power's proposal to expand the revenue offset provision in the contributions policy to include residential customers.

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[708] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 258-259.

[709] Western Power, *Access arrangement information*, 2 October 2017, p. 268, section 12.3.1 and *Access arrangement information: Attachment 12.4,* 2 October 2017, p. 4.

[710] Western Power, *Access arrangement information: Attachment 12.4,* 2 October 2017, p. 4.

2816. The provision for revenue offset was applied under clause 5.2 (calculation of contribution) of the contributions policy.

2817. Western Power's initial proposal included several proposed changes to the wording of clause 5.2 of the contributions policy. Given Western Power's comments about not needing "any specific wording change" in the policy, these changes were considered consequential to Western Power's proposal to delete the headworks scheme (existing clause 6) from the policy, which is addressed at paragraph 2828 below.

2818. Subject to clause 6 being deleted from the contributions policy, clause 5.2 read as follows:

> 5.2 Calculation of Contribution
>
> The contribution payable in respect of any works to which this policy applies is calculated by:
>
> (a) determining the appropriate portion of any of the forecast costs of the works (excluding distribution low voltage connection headworks scheme works, but including any works relating to a distribution low voltage connection headworks scheme application excluded from clause 6 by clause 6.5), which do not meet the new facilities investment test or the alternative option test (as applicable) to allocate to the applicant under clause 5.4; and
>
> (b) adding any applicable amount calculated under clause 6.3 (distribution low voltage connection headworks scheme base charge), and
>
> (c) adding any applicable amount calculated under clause 7.41.1(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, to the customer's retailer, as calculated over the reasonable time, at the contributions rate of return; and
>
> (e) adding any applicable amount calculated under clauses 7.1, 7.3 and 7.5; and
>
> (f) adding any tax liability (of the nature referred to in clause 4.4) which Western Power forecasts it will incur due to the receipt of the amount payable under paragraphs (a) to (e) of this clause 5.2, as calculated in accordance with clause 5.5; and
>
> (g) adding any applicable amount calculated under clause 7.2.

2819. The proposed wording of clause 5.2(c) contained a cross-referencing error. The reference to "clause 7.41.1(a)" should be a reference to "clause 7.4(a)".

2820. In its draft decision, the ERA considered Western Power's proposal to expand the revenue offset to residential customers was consistent with section 5.12(a) of the Access Code as it achieved the objective of striking the balance between the interests of contributing users, other users and consumers (which includes residential customers). While the ERA agreed that clause 5.2 of the contributions policy was not required to be amended in order to give effect to this "change", the ERA was of the view that the revenue offset in clause 5.2 should always have been applicable to residential customers. The ERA therefore considered that this proposal was not a *change* nor an *expansion*. However, in order to make that position express the following amendment to clause 5.2(d) was required:

> (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;

2821. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 83**
>
> Clause 5.2(d) of the contributions policy must be amended in accordance with paragraph 1747 of this draft decision [paragraph 2820 above] 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)"*.

2822. In its revised proposal, Western Power has accepted required amendment 83 and has made the required amendments to clause 5.2.[711]

2823. No submissions on this matter were received in response to the draft decision.

2824. The ERA is satisfied that Western Power has complied with draft decision required amendment 83.

Other amendments

2825. Western Power's initial proposal included other amendments to the contributions policy. These were shown as mark-ups to the policy, and included wording changes to clause 5.4, clause 6.3 (previously clause 7.3) and the meaning of "distribution low voltage connection headworks scheme application" in clause 1.1. Other amendments included the deletion of all terms and references relating to the distribution headworks scheme and the updating of clause numbering and cross-references throughout the policy.

2826. Western Power proposed to add the words "acting as a reasonable and prudent person" to clause 5.4(c)(ii) of the contributions policy. These words mirrored the existing wording used in clause 5.4(c)(i) of the policy.

2827. Unless stated otherwise in this decision, the other proposed amendments were considered consequential and/or administrative amendments to:

- Expand the distribution low voltage connection headworks scheme and associated methodology document (at Appendix C.2).
- Give effect to the proposed deletion of the distribution headworks scheme.

Distribution headworks scheme

2828. Western Power proposed to delete the distribution headworks scheme (including associated references and methodology) from the contributions policy, noting that it was not a mandatory requirement of the Access Code to include such a scheme. Western Power's reason for deleting the scheme was as follows:[712]

> The distribution headworks scheme was introduced for the [AA2] period, with the purpose of providing a levelised $/kVa charge for upgrades to power supply in rural and regional areas situated 25 kilometres or more from the nearest Western Power

[711] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 259-260.

[712] Western Power, *Access arrangement information*, 2 October 2017, pp. 268-269, paragraphs 1131 and 1132.

> substation. Under the scheme, Western Power recovers only a portion of the cost for supply upgrades upfront, with future connections forecast to contribute the balance.
>
> The outstanding costs rarely meet the NFIT (due to being outside natural load growth scenarios) and, given the lack of growth in regional areas, the upgrade costs are rarely recovered from the actual customer or customers served. Instead, these costs are being recovered from all customers (where the costs meet NFIT) or borne by Western Power directly (where the costs do not meet NFIT). For this reason we propose to remove the scheme.

2829. Western Power further noted:[713]

- While it had made a commitment to the State Government not to charge for headworks in the 2012/13 financial year, the distribution headworks scheme (and methodology) has not been applied since.
- The charges for customers that may have previously been subject to the distribution headworks scheme would be determined consistent with the methodology applied to supply upgrades in regional areas. That is, Western Power would charge the forecast cost of the works required to connect the customer, minus any portion of the costs deemed to meet the new facilities investment test.

2830. No submissions on Western Power's initial proposal commented on the proposal to delete the distributions headworks scheme from the contributions policy.

2831. Provisions for the distribution headworks scheme are set out in clause 6 of the current contributions policy, with the scheme methodology set out in Appendix C.2 of the current access arrangement.

2832. In its draft decision the ERA agreed there was no requirement in the Access Code to include such a scheme. Hence, Western Power's proposal to delete the distribution headworks scheme (existing clause 6); methodology (existing Appendix C.2); and all associated references to the scheme (which are considered consequential amendments) was not inconsistent with the requirements of the Access Code.

2833. Western Power's revised proposal does not readdress this matter and no submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2832 above.

Distribution low voltage connection headworks scheme

2834. In its initial proposal Western Power proposed to expand the Distribution Low Voltage Connection Headworks Scheme (DLVCHS) to include all new capacity connections (but to exclude the connection of gifted assets). Currently the scheme applies only to connection upgrades ("brownfield works") and not to new connections ("new lots").

2835. Western Power stated that the expansion of the scheme to include new connections would:[714]

[713] Western Power, *Access arrangement information: Attachment 12.4*, 2 October 2017, p. 2.

[714] Western Power, *Access arrangement information*, 2 October 2017, p. 269, paragraph 1136.

- enable the development industry to more accurately forecast charges
- implement consistent charging across customers
- provide customers with more predictable and transparent prices
- streamline the processes for determining charges by providing a simpler approach to charging customers

2836. The proposed amendments to the DLVCHS were outlined in a marked-up copy of the *distribution low voltage connection scheme methodology* (at Appendix C.2) and in Attachment 12.5[715] to the initial proposed access arrangement. The amendments included:

- Changes to some clauses in the methodology to extend the application of the DLVCHS to all new capacity connections (excluding the connections of gifted assets).
- A new section (1.1) to insert information for interpretation.
- Other drafting amendments, including amendments to terminology, to ensure consistency between the scheme's methodology and contributions policy.

Expansion of the DLVCHS (sections 1; 2.3; 4; 5.1; and 6)

2837. Western Power's proposal to expand the DLVCHS meant that the definition of the scheme required amendment. The DLVCHS methodology document (at Appendix C.2 of the proposed access arrangement) stated that the:

> **"distribution low voltage connection scheme"** means the scheme described in clause 6[716] of the *contributions policy*.

2838. Proposed amendments to the contributions policy to give effect to the expansion of the DLVCHS were discussed at paragraph 2825 above. Amendments to the DLVCHS methodology document (Appendix C.2) included changes to:

- Some defined terms used in the methodology (at section 1).
- The drafting of section 2.3, which provides an overview of the scheme.
- Section 4, which provides an overview of the methodology used to determine the scheme's prices.
- Section 5.1, which provides additional detail about the price determination process.
- Section 6, which provides details about when an application is excluded from the provisions of the scheme.

Section 1 – definitions

2839. Section 1 of the DLVCHS methodology contains a list of defined terms that are used. Western Power proposed to amend several terms and delete some others.

- Amendments are proposed for the following terms:
  - "applicant"
  - "distribution low voltage connection scheme application"

[715] Distribution Low Voltage Connection Scheme Change Summary.

[716] Previously clause 7 of the contributions policy.

- "distribution low voltage connection scheme base charge"
- "distribution low voltage connection scheme works".

- The terms "headworks"; "headworks charge"; "headworks scheme"; "scheme"; and "street feed" were to be deleted.

2840. The proposed amendments to the abovementioned terms all made reference to the terms used in the contributions policy. That is, *the defined term has the same meaning given to it in the contributions policy*. To assist the reader, notes to the definition reproduce the meaning as contained in the contributions policy; for example:

> **"applicant"** has the same meaning given to it in the *contributions policy*.
>
> {Note: Under the contributions policy "applicant" means "a person (who may be a user, a customer or a developer) who has lodged, or intends to lodge, a connection application, and includes a person who does so on behalf of another person".}

2841. The proposed amendments simply referred to (and reproduced) terms and meanings in the contributions policy. The proposed terms to be deleted were consequential to the deletion of the distribution headworks scheme (which has been addressed at paragraph 2828 above).

2842. Due to the insertion of a new interpretation section (see paragraph 2877 below) in its draft decision the ERA required section 1 to be renamed "defined terms and interpretation" and insertion of a new section 1.1 ("defined terms").[717] The ERA considered that this would make the DVLHS methodology consistent with the format of the contributions policy.

2843. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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~~ <u>Defined Terms</u>

2844. In its revised proposal, Western Power has accepted draft decision required amendment 84 and has made the required amendments to rename sections.[718]

2845. No submissions were received on this matter in response to the draft decision.

2846. The ERA is satisfied that Western Power has complied with draft decision amendment 84.

Section 2.3 – overview of the distribution low voltage connection scheme

2847. In its initial proposal Western Power proposed to change the drafting of section 2.3, which provided an overview of the scheme. The proposed changes were as follows:

> 2.3 Overview of the Distribution Low Voltage Connection Scheme

[717] Proposed new section 1.1 (interpretation) will become section 1.2.

[718] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 261.

(a) The distribution low voltage connection headworks scheme and associated prices apply to the provision of distribution low voltage connection headworks scheme works only. The class of applicants must meet the following criterion~~a~~:

(i) T~~t~~he 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~~, and~~

~~(ii) the applicant's required electrical capacity is in excess of:~~

~~(A) the original design capacity for a greenfield development on an existing electricity serviced lot, or~~

~~(B) the existing capacity in respect of that connection point for a brownfield development.~~

(b) The prices are in terms of $/kVA.

(c) The ~~headworks charge~~price that an applicant pays depends on their incremental capacity requirement~~required electricity demand~~ and whether the location of the connection point is on a land lot separate from the relevant distribution transformer~~there will be a distribution transformer on the lot where the connection point is located~~.

2848. As indicated, Western Power was proposing to expand the DLVCHS to include new connections. The proposed drafting changes to section 2.3 of the DLVCHS methodology document reflected this expansion. The ERA's draft decision required some minor amendments to section 2.3(a) to reflect common drafting conventions as follows.

(a) The distribution low voltage connection headworks scheme and associated prices apply to the provision of distribution low voltage connection headworks 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.

2849. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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 of this draft decision [paragraph 2848 above] to reflect common drafting conventions.

2850. In its revised proposal, Western Power has accepted draft decision required amendment 85 with some formatting modifications to present the clause as a single clause (with no sub-clauses).[719]

2851. No submissions were received in response to the ERA's draft decision.

2852. The ERA is satisfied that Western Power has complied with draft decision required amendment 85.

[719] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 262.

Section 4 – methodology overview

2853. Section 4 of the DLVCHS methodology document provides an overview of the methodology used to determine the scheme's prices. In Western Power's initial proposal the following drafting changes were proposed:

> 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:
>
> (i) the incremental capacity requirement~~amount of capacity~~ sought by an applicant; and
>
> (ii) whether the location of the connection point is on the same land lot as the relevant distribution transformer~~whether the location of the connection point is contiguous to the location of the transformer~~, or whether the connection point is supplied from the low voltage street network.
>
> 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~~a~~ 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~~7~~.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 the location of the connection point on the same land lot as the relevant distribution transformer~~whether the location of the connection point is on a lot separate from the location of the transformer~~, or whether the connection point is supplied from the low voltage street network.
>
> (c) From the costs of distribution low voltage connection scheme work and the incremental ~~electricity demand~~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 land lot as the relevant distribution transformer~~connections with a contiguous transformer~~ to those with a connection point supplied from~~connected to~~ the low voltage street network.

2854. The proposed drafting changes to section 4 of the DLVCHS methodology were for the purpose of adding clarity and did not make any substantive changes to the meaning of section 4. In its draft decision, the ERA made the following additional changes to clause 4 in order to correct some formatting and typographical errors:

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)~~(i)~~ the incremental capacity requirement sought by an applicant; and

(b)~~(ii)~~ whether:

(i) the location of the connection point is on the same land lot as the relevant distribution transformer;~~,~~ or

(ii) ~~whether~~ the connection point is supplied from the low voltage street network.

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 land lot as the relevant distribution transformer;~~,~~ or

(B) ~~whether~~ the connection point is supplied from the low voltage street network.

2855. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision Required Amendment 86

The drafting of section 4 of the distribution low voltage connection scheme methodology must be amended in accordance with paragraph 1768 of this draft decision [paragraph 2854 above] to correct some formatting and typographical errors.

2856. In its revised proposal, Western Power has accepted draft decision required amendment 86 and has made the required amendments to section 4.[720]

2857. No submissions were received on the ERA's draft decision.

2858. The ERA is satisfied that Western Power has complied with draft decision required amendment 86.

[720] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 262.

Section 5.1 – price tranche thresholds

2859. Section 5 of the DLVCHS methodology provides details on the price determination process, with section 5.1 outlining the price tranche thresholds. In its initial proposal Western Power proposed to amend the drafting of the section as follows:

> 5.1 Price Tranche Thresholds
>
> Western Power has developed standard distribution low voltage connection scheme prices based on modelling of connections over the ~~past~~ 12 month period since the most recent review of prices. Costs per unit of capacity (kVA) reduce as the demand increases due to economies of scale. Those economies reflect the following factors;
>
> - fixed costs including cable trenching, reinstatement, traffic management, mobilisation costs and installation costs are incurred regardless of capacity supplied,
> - increased utilisation of installed assets, and
> - reduction in the per unit cost of transformers in terms of dollars per kVA of capacity. (transformers are purchased in standard sizes, typically 315 kVA, 630 kVA and 1000 kVA and on a per kVA basis the costs of these transformers reduce significantly as the size increases).
>
> In order for these economies of scale to be recognised in the pricing structure thresholds are set that reflect both the cost of plant and the nature of the network required to provide the requested capacities. For example, in general customers seeking less than 216 kVA are supplied from the low voltage street network~~distribution network~~, customers seeking demand between 216 kVA and 630 kVA require installation of a new transformer and may require that transformer to be installed on their lot, and in almost all circumstances customers seeking loads in excess of 630 kVA will require direct connection to a new transformer on their lot. Consequently the thresholds identified are:
>
> (a) Tranche 1 - ~~for the~~less than ~~first~~ 216 kVA of ~~requested load~~incremental capacity requirement,
>
> (b) Tranche 2 - between 216 kVA and 630 kVA~~for additional units~~ of incremental capacity requirement~~load from 216 kVA to 630 kVA~~, and
>
> (c) Tranche 3 - greater than 630 kVA~~for additional units~~ of incremental capacity requirement~~load above 631 kVA~~.

2860. The proposed changes amended 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 considered this change to be ambiguous because “the 12 month period since” could be interpreted as forward looking. The ERA considered that the amendment had 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 required the current drafting be reinstated, which was considered clearer.

2861. In its draft decision the ERA considered that the other proposed changes made to clause 5.1 could be accepted on the basis that they were considered improvements to the drafting and did not alter the meaning of the clause.

2862. The ERA’s draft decision required the following amendment to Western Power’s proposal.

> **Draft Decision 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”).

2863. In its revised proposal, Western Power accepts draft decision required amendment 87 in principle with modifications.[721]

> 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).
>
> 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.
>
> 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.
>
> 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~~ develops~~ed~~ standard distribution low voltage connection scheme prices based on modelling of connections over at least the past 12 month period.

2864. No submissions were received on the ERA's draft decision.

2865. When the ERA first approved the DLVCHS in September 2012 it noted:[722]

> The standard charges would be based upon the average costs for the provision of capacity (kVA) for customers eligible for this service. The actual contribution for these customers would be net of expected additional (incremental) revenue.
>
> Western Power will update the standard charges annually to reflect the actual augmentation costs for works undertaken during the previous 12 month period. The Authority notes that section 7 of the DLVCHS Methodology also provides for Western Power to review the prices and exclusion threshold periodically to reflect changes in the cost of provision of network assets. Any adjustments will apply for a minimum of six months.

2866. In its decision in September 2012 the ERA agreed that 12 months was a reasonable period of time for a review of prices. If Western Power updates its prices on a 12 monthly basis, it does not need to make the amendments it proposed in its revised proposal for AA4. That is, it does not need to insert the words "at least" in section 5.1.

2867. While finalising this amendment, the ERA has identified that section 2.2 of the version of the DLVCHS provided with Western Power's initial submission for AA4 is not consistent with the version approved by the ERA in September 2012. In the version provided with Western Power's initial AA4 proposal the time period in the following extract from section 2.2 is shown as 18 months, rather than the 12 months approved by the ERA in September 2012.

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[721] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 263-264.

[722] Economic Regulation Authority, Final Decision on Proposed Variations to Western Power's Access Arrangement for 2009/10 to 2011/12: Contributions Policy, 3 September 2012, p. 4.

> … The prices of the *distribution low voltage connection headworks scheme* are to be reviewed not less than once every 12 months to reflect the actual costs of the provision of *distribution low voltage connection headworks scheme works*.

2868. Western Power has confirmed this was an error and that it should be 12 months to be consistent with the approved version.[723] However, Western Power advised that it considers 18 months is a more appropriate timeframe for the price review as the current wording "not less than once every 12 months" requires reviews more frequently than 12 months.

2869. The ERA considers this could be dealt with by amending the words to "at least once every 12 months" to clarify that, as set out in the ERA's decision in September 2012, prices will be updated annually.

2870. The ERA requires Western Power to amend section 2.2 to be consistent with the document approved by the ERA in September 2012 and to delete the words "at least" from section 5.1 of the DLVCHS.

Required Amendment 64

Section 2.2 of the DLVCHS must be amended to state prices are reviewed at least once every 12 months.

The proposed insertion of the words "at least" into the first paragraph of section 5.1 of the proposed Contributions Policy Appendix C.2 should be deleted.

Section 6 – exclusion

2871. Western Power proposed to amend some wording in section 6 of the DLVCHS methodology, which outlines the method for determining the exclusion threshold for the scheme:

> 6 Exclusion
>
> A distribution low voltage connection scheme application …
>
> 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 ~~customer~~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.

2872. The proposed changes amended the time period for determining the exclusion threshold from "the last twelve months" to the "12 month period since the most recent

[723] Western Power response to ERA074 Query received by email on 11 September 2018.

review of prices." For the reasons given at paragraph 2860 above, the ERA considered this change to be ambiguous and was not to be made.

2873. The ERA considered the proposed change to replace the word "customer" with the word "applicant" clarified that the determination of the forecast costs of the works applies to applicants (rather than customers), and was consistent with section 5.4 of the contributions policy.

2874. The ERA's draft decision required the following amendment to Western Power's proposal.

> **Draft Decision 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").

2875. In its revised proposal, Western Power accepts draft decision required amendment 88 in principle with modifications.[724]

> Similar to Western Power's response to amendment 87, we propose the following modifications to clause 6 of the DLVCHS:
>
> …
>
> (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:

2876. As discussed in paragraph 2866 above, the ERA considers Western Power's initial proposal to amend this clause was unnecessary as Western Power is required to review prices every 12 months. Consequently, the ERA requires Western Power to retain the current wording in clause 6(a):

> For all *works* in the *last twelve months* Western Power will:
>
> …

Required Amendment 65

The proposed insertion of the words "over the same period over which connections are modelled under clause 5.1" into subclause 6(a) of the proposed Contributions Policy Appendix C.2 should be deleted and the words "in the last twelve months" must be retained..

Interpretation (proposed section 1.1)

2877. Western Power proposed to insert a new interpretation section (section 1.1) into the DLVCHS methodology as follows to ensure consistency with other instruments (including the contributions policy) and clearer interpretation:[725]

> 1.1 Interpretation
>
> (a) Unless the contrary intention is apparent:

[724] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 264-265.
[725] Western Power, *Access arrangement information: Attachment 12.5*, 2 October 2017, p. 2.

(i) a rule of interpretation in the Code; and

(ii) the Interpretation Act 1984,

apply to the interpretation of this methodology document.

(b) Unless:

(i) the contrary intention is apparent: or

(ii) the term has been redefined above or in the contributions policy,

a term with a defined meaning in the Code has the same meaning in this methodology document.

2878. The ERA considered that inserting an interpretation clause would add clarity to the methodology document by explaining how the methodology and defined terms in the methodology are to be interpreted. In addition it is standard practice for an interpretation clause to be inserted into a document of this nature. However, the ERA considered that paragraph 1.1(b)(ii) was ambiguous. The ERA required the following amendments 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. Consistent with the ERA's requirement to rename section 1 and introduce a new section 1.1 (refer to paragraph 2842 above), proposed section 1.1 became section 1.2:

1.2~~1.1~~ Interpretation

(a) 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.

(b) 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.

2879. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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.

2880. In its revised proposal, Western Power has accepted draft decision required amendment 89 and has made the required amendments.[726]

2881. No submissions were received on the ERA's draft decision.

2882. The ERA is satisfied that Western Power has complied with draft decision required amendment 89.

[726] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 265-266.

Price structure (section 5.4)

2883. The price structure under the DLVCHS is based on a set of per kVA rates that reflect the average cost of supply per unit of load (kVA). Section 5.4 of the DLVCHS methodology provides illustrative prices for the scheme, with actual prices being published separately on Western Power's website.[727]

2884. Western Power noted that the pricing under the scheme had not been updated since October 2012.[728] As part of its review of policies and schemes for AA4, Western Power reviewed this pricing and is proposing new prices, to commence from 1 July 2018. The proposed prices (charges) compared with current prices are set out in Table 184 below.

Table 184 Western Power's proposed distribution low voltage connections headworks scheme pricing

	Current charge $	Proposed charge $	Change $	% change
Tranche 1 TX charge	448.00	546.61	98.61	22%
Tranche 2 TX charge	224.00	273.31	49.31	22%
Tranche 3 TX charge	112.00	136.65	24.65	22%
Tranche 1 LV charge	496.00	602.55	106.55	21%
Tranche 2 LV charge	272.00	329.24	57.24	21%

Source: Western Power, Access arrangement information: Attachment 12.5, 2 October 2017, p.4, section 3.

2885. In its initial proposal, Western Power stated that it conducted an internal review of the average costs based on compatible unit costs for works issued to construction. Included in its assessment is the application of Consumer Price Index and labour rate escalators to the equivalent of 2.75 per cent per annum from 2012 rates to those proposed for 2018/19.

2886. The ERA considered that the illustrative prices in clause 5.4 were consistent with the requirements in section 5.17D of the Access Code. This is because the indicative pricing is for the purpose of giving additional detail to the methodology that is used to calculate the headworks charge.

2887. As discussed above (paragraph 2865 to 2867), the current DLVCHS requires Western Power to review prices every 12 months. The fact that Western Power has not reviewed prices since October 2012 is likely to have been favourable to customers who have paid contributions under the DLVCHS (as construction costs most likely increased over the period) but could have resulted in network users paying more than they should. However, it is unlikely this amount would be significant.

2888. The ERA expects that, in future, Western Power will undertake price reviews on an annual basis.

[727] Information on the DLVCHS, including pricing can be found at: https://westernpower.com.au/technical-information/distribution-low-voltage-connection-headworks-scheme-dlvchs/ (accessed 12/02/2018).

[728] Western Power, *Access arrangement information: Attachment 12.5*, 2 October 2017, p. 4.

DLVCHS Amendments proposed after draft decision

2889. Western Power's revised proposal includes new proposed amendments to the DLVCHS. Western Power submits:[729]

> 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.
>
> 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.
>
> 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

[729] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 266-267.

(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.

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.

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.

2890. As explained in section 5.3 of the DLVCS, direct connection to a transformer is less costly than a connection to the low voltage street network as additional assets are needed to connect to the street network. Currently the scheme only specifies properties on the same lot as a transformer as being eligible for the lower charge. The proposed amendment expands this to properties on adjoining or nearby land where Western Power determines a transformer direct connection is the most prudent and efficient network connection design.

2891. The ERA considers the proposed amendment is consistent with the requirements of the Access Code and will ensure customers are connected in the most cost efficient manner and charged the costs of that connection.

Other matters raised by interested parties

Approach to tax recovery

2892. In its submission, WALGA raised concerns over the treatment and recovery of tax on capital contributions. It noted the following:[730]

> Under the Australian Accounting Standards, gifted assets are treated as assessable income. As a result, gifted assets increase Western Power's National Tax Equivalent Regime payments to the State Government. As part of Western Power's Third Access Arrangement, the ERA ruled that it is more appropriate for these costs to be passed onto the customer requesting the work. Western Power has since commenced recovery of the tax on capital contributions from 5 January 2015 at a rate of 13.9% for industrial and commercial projects.

2893. WALGA submitted that local governments were affected by this policy to recover the tax on capital contributions because local governments pay for the cost of asset relocations and gift street lights to Western Power. While WALGA generally supported the use of upfront charges for infrastructure specifically built for new developments, it did not support the tax costs resulting from capital contributions being recovered from the entity (or entities) making the contribution.

2894. WALGA stated that recovering tax costs from those making a contribution "is not necessarily an efficient outcome and is likely to have significant distortions on activity".[731] A street lighting project in the Shires of Esperance and Leonora was provided to illustrate the magnitude of the potential tax implications.[732] It further stated that it:

> … understands the ERA's decision on the treatment of capital contributions is not consistent with what occurs in other jurisdictions. For example, the Australian Energy Regulator (AER) makes an allowance for tax costs in the infrastructure provider's overall revenue requirement, which potentially enables these costs to be recovered from all users.
>
> The ERA should examine the merits of adopting the same approach used in the AER jurisdictions.

2895. The ERA considered the treatment and recovery of tax on capital contributions as part of its assessment of Western Power's access arrangement for AA3. In its AA3 final decision the ERA explained how capital contributions lead to a tax liability for Western Power, the potential value of such a liability and how it should be recovered:[733]

> Under tax law, a capital contribution which relates to an asset that meets the required definitions becomes revenue for Western Power in the year of receipt, which is matched to a 'fair value' entry in Western Power's tax asset base (TAB).
>
> Western Power then becomes liable for tax at 30 per cent on that revenue in the first year, and for deductions from its tax liabilities in the out-years tax reflecting the depreciation of the TAB contributed asset.

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[730] WALGA, Submission to the Economic Regulation Authority, December 2017, p. 11.

[731] WALGA, Submission to the Economic Regulation Authority, December 2017, p. 12.

[732] WALGA states that for the street light project within the Shires a tax of 13.9% would have had an impost of almost $800,000.

[733] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 5 September 2012, pp. 248-249, paragraphs 1087 to 1091.

> Given that Western Power's tax account is in nominal terms, the net present value (NPV) of the stream of future depreciation tax liability deductions is less than the upfront cost of the tax liability. This 'time value of money' is significant, and could result in a substantial cost for Western Power. It therefore may be reasonable for Western Power to pass this cost on to the developer.
>
> The Authority accepts that a capital contribution could lead to a tax liability for Western Power of 25 per cent of the value of contributed assets.
>
> The Authority considers that rather than customers funding these costs, it would be more appropriate for Western Power to obtain recompense for these costs as part of the commercial negotiations or evaluation of charges related to any contribution.

2896. The ERA concluded that:[734]

- the tax costs associated with capital contributions may not necessarily be associated with efficient costs – as is the case where a contribution is required for an augmentation that does not meet the NFIT;
- to allow tax costs that are not associated with efficient costs to be charged to all customers would be inconsistent with the objectives of the [Access] Code;
- Western Power does have a tax liability associated with a contribution, but given the objective of economic efficiency and the associated principal of 'user pays', this should be recovered from the contributor – to do otherwise would lead to a subsidy from the existing customer base to the contributing entity;[735]
- Western Power and the contributor are best placed to work out the commercial terms of the tax implications of any contribution, taking into account their business interests and tax positions;
- the analysis provides support for the [ERA] taking a different position to that of other regulators.

2897. In the draft decision, the ERA considered there was no reason to vary its position on the treatment and recovery of tax on capital contributions when assessing Western Power's proposal for AA4.

2898. No submissions on this matter were received in response to the draft decision.

State Underground Power Program

2899. CdL Advisory's submission on the contributions policy questioned the percentage of contributions that Western Power assumed for the SUPP and how it corresponded to the ERA's 2010 inquiry into the program.[736]

2900. In its initial proposal, Western Power stated that:[737]

> SUPP contributions are forecast in accordance with a capital and operating cost sharing agreement between State Government, local government and Western Power.

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[734] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 5 September 2012, p. 250, paragraph 1103.

[735] Generally the contributor would pay the value arising from the timing difference of the tax payment and subsequent recovery, not the total tax payment.

[736] See: https://www.erawa.com.au/inquiries/energy-inquiries/costs-and-benefits-of-the-state-underground-power-program-2010 (accessed 12/02/2018)

[737] Western Power, *Access arrangement information,* 2 October 2017, p. 182, paragraphs 717 and 718.

> Typically, local governments will contribute at least 50 per cent of costs, with Western Power and/or State Government contributing the balance.
>
> Western Power assumes a 54 per cent contribution rate for distribution customer driven works. This reflects the AA3 average recovery rate for contributions for the SUPP.

2901. The ERA undertook an inquiry into the costs and benefits of the SUPP in April 2010. In its final report, the ERA recommended that:[738]

> The costs of retrospective underground power should be recovered from the following beneficiaries, based on the variable proportion of quantifiable and qualitative benefits that they each receive:
>
> - Western Power should contribute an amount equal to its avoided costs when a particular project area is undergrounded (on average between 15 and 35 per cent but could be more or less than this);
> - The State Government could contribute between 5 and 40 per cent, depending on the median house price and socio-economic indicators of a project area; and
> - Local governments (through ratepayers) could contribute the residual amount (total costs less Western Power's avoided costs and the contribution from the State Government), which may be between 25 and 80 per cent.

2902. The Western Australian State Government last invited local governments to submit proposals for round six of the SUPP in December 2015. New funding arrangements for round six were introduced to reflect the priorities of the State Government, experience gained in previous funding rounds and the ERA's inquiry findings:[739]

> 2.1 New Project Funding Arrangements
>
> 2.1.1 Local Government Funding Contribution
>
> For Round Six of the Program, local governments will nominate the proportion of project funding they are willing to pay. The minimum contribution from local governments will be 50 per cent.
>
> Project proposals offering a greater contribution share will receive a higher score in the selection process and be more competitive.
>
> This arrangement will allow for more projects to be implemented within the approved Program budget. It will also better align funding contribution shares with the proportionate benefits received by Program participants. This approach is consistent with the findings made by the Economic Regulation Authority in a report titled Inquiry into State Underground Power Program Cost Benefit Study (the Inquiry Report).
>
> 2.1.2 Western Power Funding Contribution
>
> Western Power's project funding contributions will vary according to the costs that it avoids through undergrounding of distribution systems. These avoided costs are determined through the New Facilities Investment Test and are reviewed by the Economic Regulation Authority under the Electricity Networks Access Code 2004 (the Code). This approach is consistent with the findings of the Economic Regulation Authority in its Inquiry Report.
>
> The New Facilities Investment Test is established under the Code and provides a method to assess the justification of each new network augmentation and the efficiency of proposal expenditure. It is the measure used to determine whether

[738] Economic Regulation Authority, *Inquiry into State Underground Power Program Cost Benefit Study: Final Report*, 30 September 2011, p. 79, finding #25.

[739] Government of Western Australia, Department of Finance, Public Utilities Office, *State Underground Power Program: Major Residential Projects Round Six Guideline*, December 2015, pp. 3-4, section 2.1.

Western Power is following good business practice in efficiently minimising its capital investments to meet forecast demand.

Horizon Power is not subject to the Code and does not use the New Facilities Investment Test. If a submission is received that relates to Horizon Power's electricity network, the specific circumstances relating to the project will be used to determine Horizon Power's project funding contribution.

2.1.3 Determining Contribution Amounts

Funding requirements for each project will be determined by the following sequence:

- Local governments will contribute between 50 and 100 per cent of the project cost as specified in the project proposal.
- Western Power's project funding contributions will vary according to the project costs that meet the New Facilities Investment Test.
- Where the sum of the local government contribution and the Western Power contribution exceeds 100 per cent of the expected project value, the Western Power contribution will reduce by the amount that exceeds 100 per cent.
- The remaining balance (if any) will be provided by the Government of Western Australia through the Department of Finance, Public Utilities Office.

A total cost cap of $11 million will be applied to individual project funding to maximise the number of projects the Program is able to deliver. If a project will cost more than this amount, the local government will be required to pay 100 per cent of the additional costs.

2903. Consistent with the ERA's 2010 inquiry findings, the round six SUPP funding arrangements required Western Power to contribute an amount equal to its avoided costs as determined by the new facilities investment test under the Access Code. At the time of the inquiry, the ERA estimated this amount to be on average between 15 and 35 per cent, noting that the amount could be more or less than this.

2904. The round six SUPP guidelines set out the process for determining contribution amounts. Under the process local governments are required to contribute somewhere between 50 and 100 per cent of the project cost. Western Power will contribute an amount equal to the project costs that meet the new facilities investment test. In instances where the total contribution from local government and Western Power exceeds the expected project value (100 per cent), Western Power's contribution will be reduced by the amount that exceeds 100 per cent. Any remaining balance (if any) will be met by the State Government.

2905. The way in which the SUPP is administered, including how contribution amounts from program participants are determined, is a matter for the State Government. Western Power's assumptions for the SUPP (including a 54 per cent contribution rate) were considered appropriate for its budgeting and planning purposes, noting that Western Power's project (capital) costs are assessed by the ERA either:

- During the access arrangement period, where Western Power makes an application to the ERA for it to determine whether actual (or forecast) capital costs meet (or is forecast to meet) the new facilities investment test.
- or
- As part of Western Power's access arrangement proposal for the next access arrangement period.

2906. The ERA's assessment of Western Power's actual capital costs for the AA3, and forecast capital costs for AA4, are set out in the *Total Revenue Requirement* chapter.

2907. No submissions on this matter were received in response to the ERA's draft decision.

TRANSFER AND RELOCATION POLICY

Access Code requirements

2908. Section 5.1(i) of the *Electricity Networks Access Code 2004* (Access Code) requires that an access arrangement include a transfer and relocation policy, which is a policy that:

> specifies a user's rights to transfer its access rights to another person and relocate capacity from one connection point in its access contract to another connection point in its access contract.

2909. The particular requirements for a transfer and relocation policy are set out in sections 5.18 to 5.24 of the Access Code as follows:

5.18 A transfer and relocation policy:

(a) must permit a user to make a bare transfer[740] without the service provider's consent; and

(b) may require that a transferee under a bare transfer notify the service provider of the nature of the transferred access rights before using them, but must not otherwise require notification or disclosure in respect of a bare transfer.

5.19 For a transfer other than a bare transfer, a transfer and relocation policy:

(a) must oblige the service provider to permit a user to transfer its access rights and, subject to section 5.20, may make a transfer subject to the service provider's prior consent and such conditions as the service provider may impose; and

(b) subject to section 5.20, may specify circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.19(a).

5.20 Under a transfer and relocation policy, for a transfer other than a bare transfer, a service provider:

(a) may withhold its consent to a transfer only on reasonable commercial or technical grounds; and

(b) may impose conditions in respect of a transfer only to the extent that they are reasonable on commercial and technical grounds.

5.21 A transfer and relocation policy:

(a) must permit a user to relocate capacity at a connection point in its access contract to another connection point in its access contract, (a 'relocation') and, subject to section 5.22, may make a relocation subject to the service provider's prior consent and such conditions as the service provider may impose; and

(b) subject to section 5.22, may specify in advance circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.21(a).

5.22 Under a transfer and relocation policy, for a relocation a service provider:

[740] A *bare transfer* is a transfer where the user's obligations under the contract for services and all other terms of the contract for services remain in full force and effect after the transfer.

(a) must withhold its consent where consenting to a relocation would impede the ability of the service provider to provide a covered service that is sought in an access application; and

(b) may withhold its consent to a relocation only on reasonable commercial or technical grounds; and

(c) may impose conditions in respect of a relocation only to the extent that they are reasonable on commercial and technical grounds.

5.23 An example of a thing that would be reasonable for the purposes of sections 5.20 and 5.22 is the service provider specifying that, as a condition of its agreement to a transfer or relocation, the service provider must receive at least the same amount of revenue as it would have received before the transfer or relocation, or more revenue if tariffs at the destination point are higher.

5.24 Section 5.23 does not limit the things that would be reasonable for the purposes of sections 5.20 and 5.22.

Current access arrangement

2910. The current access arrangement includes a transfer and relocation policy at Appendix D. The policy applies to any access contract unless otherwise explicitly stated in the access contract, and includes:

- Definitions of terms and rules of interpretation.
- An indication that the transfer and relocation policy applies to any access contract unless otherwise explicitly stated in the access contract and prohibition of any transfer of rights under an access contract except as allowed for under the transfer and relocation policy.
- Provision for bare transfers of rights under an access contract.
- Provision for assignments of rights under an access contract other than a bare transfer, subject to consent of Western Power.
- Provision for a relocation by a user of contracted capacity at one connection point to another connection point, where the user has an access contract for both connection points.

Western Power's initial proposal

2911. Western Power proposed changes to the transfer and relocation policy, which it stated would:[741]

- More closely align the policy with the provisions of the Access Code.
- Make defined terms consistent with other policies and documents (such as the applications and queuing policy).
- Distinguish and clarify the boundaries and relationships between other regulatory policies and contracts.
- Clarify the criteria for consent for a requested transfer or relocation under the policy.
- Ensure the obligations and rights of involved parties are transparent.

[741] Western Power, *Access arrangement information,* 2 October 2017, p. 271, paragraph 1140.

2912. The proposed amendments to the policy included:

- A new clause (2.3) to make clear that the transfer and relocation policy is subordinate to the Access Code and is subject to any changes made to the Access Code.
- Changes to clause 5, which has provisions that apply to an assignment other than a bare transfer, to:
  - Make clear that Western Power may only withhold consent for the assignment of access rights on reasonable grounds (clause 5.1a).
  - Place the onus on the assignee to demonstrate and provide relevant information to Western Power about its capacity to take on an assignment, including its financial position (clause 5.3).
- Changes to clause 6, which has provisions for relocations of contracted capacity, to:
  - Clarify the meaning of relocation to make clear that a relocation involves the user moving capacity from one connection point to another connection point under its access contract (clauses 6.1 and 6.2).
  - Insert a new clause (6.4) to detail the circumstances and conditions for the consent of relocations, which are consistent with the requirements of the Access Code.
  - Insert a new clause (6.5) to make clear that a relocation is subject to capacity being available at the connection point and that the relocation will (if required) be processed in accordance with the applications and queuing policy.
- Amendments to some defined terms (assignee, assignor and connection point) for clarity and other administrative drafting changes to correct drafting errors.

Submissions on Western Power's initial proposal

2913. Submissions from Alinta Energy, the Australian Energy Council, Perth Energy and Synergy addressed the transfer and relocation policy. Details of these submissions were incorporated into the ERA's considerations where applicable. In summary, the matters raised included:

- The rights under customers' existing contracts, which should be retained and grandfathered if new contracts are required.
- The role of the ERA to assess Western Power's proposal, which must include an assessment of whether the updated policy meets the requirements of the Access Code.
- The need to retain a transfer and relocation policy in the access arrangement.
- The specific use of terms in the policy and the specific wording of the policy.

Considerations of the ERA

Pre-existing contractual rights

2914. In its submission on Western Power's initial proposal, Synergy claimed that it had rights that it would be prevented from exercising if certain proposed changes to the transfer and relocation policy were approved. It raised the following points in its submission:[742]

- The Access Code (section 4.34, read in conjunction with section 4.52) provides that the ERA must not approve proposed revisions that would, if approved, have the effect of depriving a person of a contractual right that existed prior to the proposed revisions being submitted (a pre-existing contractual right).
- For the ERA to perform its obligations in accordance with the Access Code objective, the ERA must first consider and identify any relevant pre-existing contractual rights. Given Synergy's confidentiality concerns, it would be pleased to discuss the pre-existing contractual rights matter with the ERA on receipt of a notice issued under section 51 of *Economic Regulation Authority Act 2003*.
- The Access Code (section 4.34) is not limited to effectively grandfathering pre-existing contractual rights of a user or an applicant, nor are contractual rights limited to a right contained in an access contract or a contract for services.
- The transfer and relocation policy is intended to provide for certain basic rights and obligations for the transfer and relocation of access rights under the Access Code. Western Power and users are not obliged to comply with the policy in circumstances where parties enter into contractual arrangements that displace or otherwise amend those basic rights and obligations.
- The “freedom to contract” provisions of the Access Code (section 2.4A) provide that Western Power and a user or applicant may negotiate, and may make and implement, an access contract for access to any service (including a service which differs from a reference service) on any terms (including terms which differ from a standard access contract). This provision is subject to an applications and queuing policy in an access arrangement, and any applicable technical rules.
- The Access Code (section 2.6) provides that nothing in the Access Code or an access arrangement prevails over or modifies the provisions of a contract for services, except for present purposes the applications and queuing policy and the technical rules. This provision does not entitle the ERA to approve any proposed revisions that would have the effect, if approved, of depriving a person of a pre-existing contractual right.

2915. The ERA addressed the matter of pre-existing contractual rights as part of its considerations on the standard access contract at paragraph 2136 (and following).

2916. In the absence of information on the claimed pre-existing contractual rights, the ERA was of the view it had no basis on which it could form a view that any proposed changes to the transfer and relocations policy deprived Synergy or any other party of a pre-existing contractual right.

2917. The ERA considered Perth Energy's view that, in the absence of a constrained network model, the transfer and relocations policy was fundamentally unfair as it treated the transfer of generation capacity around the network as like for like. The Access Code expressly attempts to address any unfairness by requiring the service provider to withhold its consent to a relocation, where it would impede the ability of the service provider to provide a covered service that is sought in an access

[742] Synergy, *AA4 Submission Number 1: Western Power’s proposed transfer and relocation policy*, 8 December 2017, p. 8, paragraphs 20 to 26.

application (section 5.22(a)). The ERA also noted that consent to a relocation may be withheld on technical grounds, which the ERA understood generally involved an assessment of the generation type and impacts on the network.

2918. No further submissions were made about pre-existing contractual rights relevant to the transfer and relocation policy in response to the ERA's draft decision and the ERA maintains its position as set out in its draft decision.

Defined terms

2919. In its submission on Western Power's initial proposal, Synergy noted several of the defined terms used in the transfer and relocation policy (at clause 1.1) have different meanings to the same terms used in the Access Code.[743] While Synergy accepted there were circumstances where variations between terms used in the Access Code and the transfer and relocation policy were necessary, it submitted the differences in meaning should be "perfunctory and minimal".[744]

2920. Synergy referred to a specific example in the use of the term *bidirectional point*, which is a term defined in the transfer and relocation policy but not defined (or used) in the Access Code. Synergy submitted the following:[745]

> [T]he term "bidirectional point" is defined and used in the [transfer and relocation policy] but is not defined or used in the Access Code. Its use in the [transfer and relocation policy] therefore introduces a new concept to the access regime by varying the definition of connection point.
>
> In relation to this approach, Synergy considers that adopting the definition of connection point in the Access Code and not applying a new definition of bi-directional point need not preclude Western Power from offering bi-directional services because the definitions of exit point and entry point are, in Synergy's view, not inconsistent with the bi-directional service concept.
>
> Synergy therefore considers the Authority must determine whether approval of the [transfer and relocation policy] with the amended Connection Point definition is consistent with the Authority's powers under the Access Code.

2921. Synergy noted the other defined terms in the transfer and relocation policy that differed from the defined terms in the Access Code did not give rise to material differences in meaning. However, as a matter of practice, Synergy considered the ERA should insist upon a strict application of Access Code definitions in the transfer and relocation policy and other access arrangement documents.[746]

2922. In its draft decision, the ERA reviewed the other defined terms in Synergy's submission and considered that, to the extent these defined terms differed from the defined terms in the Access Code, they did not give rise to material differences in meaning. Furthermore, the ERA considered the defined terms were appropriate to

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[743] Synergy has identified ten terms where this applies (see Attachment 2 of Synergy's submission: *AA4 Submission Number 1: Western Power's proposed transfer and relocation policy*, 8 December 2017, pp.15-19).

[744] Synergy, *AA4 Submission Number 1: Western Power's proposed transfer and relocation policy*, 8 December 2017, p. 9, paragraph 28.

[745] Synergy, *AA4 Submission Number 1: Western Power's proposed transfer and relocation policy*, 8 December 2017, p. 9, paragraphs 29-31.

[746] Synergy, *AA4 Submission Number 1: Western Power's proposed transfer and relocation policy*, 8 December 2017, p. 9, paragraph 32.

the context of the transfer and relocation policy and were not required to mirror the definitions in the Access Code.

2923. Concerning the definition of the term "bidirectional point" (which does not exist in the Access Code), the ERA considered that this definition added clarity to the transfer and relocation policy and therefore should be retained. The term "bidirectional point" is used in the definition of "connection point". The term "connection point" is defined in the transfer and relocation policy to include "in respect of a user, an exit point or an entry point or a bidirectional point under the user's access contract".

2924. The ERA considered, consistent with Synergy's submission, that the term "bidirectional point" was not inconsistent with the definitions of entry and exit point in the Access Code. However, the ERA disagreed that including the term "bidirectional point" introduced a new concept into the access regime. Rather, the ERA considered that it more appropriately articulated the intended concept of a bidirectional point that is a point which permits electricity to be transferred both into and out of the network.

2925. The defined terms listed in Synergy's submission were introduced as part of the proposed revisions to the access arrangement relating to the AA3 period. Synergy did not make any submissions regarding the consistency of these definitions with the Access Code as part of that review process. In addition, the ERA was not aware of any interpretation or other disputes arising as a result of the existing definitions. As such, the ERA considered that there were no reasonable grounds for revisiting these definitions as part of this proposed access arrangement.

2926. No further submissions were received on defined terms in response to the ERA's draft decision and the ERA maintains its position as set out in its draft decision.

Application of the transfer and relocation policy (clause 2)

2927. Western Power proposed to include a new clause (2.3) to make clear that the transfer and relocation policy was subordinate to the Access Code and subject to any changes made to the Access Code:

> <u>2.3 Access Code</u>
>
> <u>This transfer and relocation policy is based on the Code as in force as at the date this transfer and relocation policy is approved by the Authority. If there is an amendment to the Code after this date then the application of this transfer and relocation policy is subject to any varied or additional requirements imposed or required by those amendments.</u>

2928. No submissions addressed Western Power's proposal to insert a new clause 2.3.

2929. A transfer and relocation policy is required to be included in an access arrangement pursuant to section 5.1(i) of the Access Code. The Access Code is made by the Minister under part 8 of the *Electricity Industry Act 2004* and may be amended from time-to-time in accordance with the procedures set out in the Act. The Act also requires the Access Code to be reviewed every five years. Given these provisions, changes to the Access Code that change the requirements for a transfer and relocation policy are possible. Any changes to such requirements would need to be adhered to. For this reason Western Power's proposed amendment to make clear that the transfer and relocation policy is subject to any varied or additional requirements imposed or required by subsequent amendments to the Access Code is consistent with the requirements of the Access Code.

2930. Western Power's revised proposal does not readdress this matter and no submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2929 above.

Assignments other than bare transfers (clause 5)

2931. Western Power's proposed to make two changes to clause 5 of the transfer and relocation policy as follows:

> 5.1 Western Power's consent required
>
> For an assignment other than a bare transfer, the following provisions apply.
>
> a. A user may not assign all or any access rights without Western Power's prior written consent which consent may be withheld on reasonable commercial and technical grounds and which consent may be subject to conditions which are reasonable on commercial and technical grounds.
>
> …
>
> 5.3 Assignment to financially and technically competent persons
>
> Western Power is not required to give its consent to an assignment under clause 5.1 if, in Western Power's reasonable opinion, ~~it can reasonably demonstrate that~~ such an assignment would have the effect of materially increasing Western Power's ~~its~~ financial or technical risk under the relevant access contract. 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.

Clause 5.1

2932. Western Power stated the proposed change to clause 5.1a of the transfer and relocation policy had been made to more accurately reflect the drafting in section 5.20 of the Access Code, which states that:

> for a transfer other than a bare transfer, a service provider:
>
> (a) may withhold its consent to a transfer only on reasonable commercial or technical grounds; and
>
> (b) may impose conditions in respect of a transfer only to the extent that they are reasonable on commercial and technical grounds.

2933. No submissions addressed the proposed change to clause 5.1a.

2934. Proposed clause 5.1a substantially reproduced the requirements of section 5.20 of the Access Code (as intended by Western Power).

2935. Western Power's revised proposal does not readdress this matter and no submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2934 above.

Clause 5.3

2936. In its initial proposal, Western Power submitted the current drafting of clause 5.3 of the transfer and relocation policy placed the onus on it to demonstrate that an assignment (of a user's access rights under an access contract to another person) would increase its financial or technical risk. Western Power believed the onus should be on the assignee (and not Western Power) to demonstrate its financial and technical position.

2937. Synergy's submission on Western Power's initial proposal stated that clause 5.3 of the transfer and relocation policy "greatly enhances Western Power's right of refusal in respect of assignments other than bare transfers compared to what is generally the case with respect to assignments under most commercial contracts". Synergy also submitted that:[747]

- Clause 5.3 exceeded the standard approach to assignments and novation in commercial contracts and therefore exceeded Western Power's legitimate business interests and was not consistent with matters that the ERA must have regard to under section 26(1)(d) of the *Economic Regulation Authority Act 2003*.
- Clause 5.3 limited Synergy's ability to enter into assignments of its access rights with third parties, whether they be customers or competitors, because any proposed assignee would have a lower credit rating than Synergy (given Synergy's position as a State government-owned business). The clause would entitle Western Power to, in every case, reject a proposed assignment. There may also be incentives for Western Power to reject proposed assignments to obtain more commercially beneficial terms for itself.
- The approval of clause 5.3 would be contrary to the Access Code objectives.
- Clause 5.3 was to be deleted from the policy and replaced with a more commercially standard provision that entitles Western Power to reject a proposed assignment in circumstances where it can demonstrate the proposed assignee lacks the financial or technical capacity to perform the proposed assignor's obligations that are proposed to be assigned.

2938. The Access Code (section 5.20) permits a service provider to withhold its consent to a relocation on reasonable commercial or technical grounds. The current transfer and relocation policy provides for this by stating (at clause 5.1c) that:

> Western Power's consent shall not be unreasonably withheld or delayed where the user can satisfy Western Power (acting on reasonable commercial and technical grounds) that the proposed assignee is financially and technically capable of performing the user's obligations in respect of the assigned access rights.

2939. In its draft decision, the ERA determined that, consistent with clause 5.1c, it was reasonable to require Western Power to give consent to an assignment where it was shown that the proposed assignee was financially and technically capable of meeting obligations for the assigned access rights. Similarly, where appropriate financial and technical capabilities could not be shown, it was reasonable for Western Power to be able to withhold its consent to an assignment.

2940. The ERA disagreed with Synergy that the clause was inconsistent with the standard approach to assignment and novation in commercial contracts. This is because it is usual practice for the party requesting assignment to demonstrate the incoming party's financial and technical capabilities as it has direct access to all the relevant information. Further, the proposed drafting is consistent with clause 5.20 of the Access Code because Western Power is only permitted to withhold consent if in its

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[747] Synergy, *AA4 Submission Number 1: Western Power's proposed transfer and relocation policy*, 8 December 2017, pp. 9-10, paragraphs 33-37.

"reasonable" opinion there is a "financial or technical risk". This language mirrors the requirement in clause 5.20(a) of the Access Code that permits consent to be withheld where there are "reasonable commercial or technical grounds".

2941. For the reasons set out above, in its draft decision the ERA considered that the proposed amendments to clause 5.3 were consistent with the requirements of the Access Code, subject to deleting the redundant text ", if any," in the last line of the clause.

2942. The ERA's draft decision required the following amendment to Western Power's proposal.

Draft Decision 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."

2943. In its revised proposal, Western Power has accepted draft decision required amendment 90 and has made the required amendments to clause 5.3.[748]

2944. Synergy's submission in response to the draft decision included matters relevant to draft decision required amendment 90.[749]

> In its previous submissions, Synergy raised concern with respect to WP's proposed amendment to clause 5.3 of the transfer and relocation policy to shift the onus from WP to the assignee to demonstrate the assignee's financial and technical position in respect of an assignment. Synergy submitted the proposed amendment to clause 5.3 greatly enhances WP's right of refusal in respect of assignments other than bare transfers compared to what is generally the case with respect to assignments under commercial contracts. Synergy submitted clause 5.3 limits its ability to enter into assignments of its access rights with third parties because any proposed assignee would have a lower credit rating than Synergy and the clause would therefore entitle WP to, in every case, reject a proposed assignment.
>
> In its draft decision, the ERA has determined that subject to a minor amendment to the text of clause 5.3 WP's proposed amendments to clause 5.3 are consistent with the requirements of the Access Code. In Synergy's view, the problematic aspect of WP's proposal as approved by the ERA in its draft decision is not that WP should have the ability to refuse consent to an assignment on financial on technical grounds. Synergy's concern is that, on WP's proposed clause 5.3, any increase in the financial or technical risk arising from a change of the current party to the proposed counterparty gives WP the right to refuse consent.
>
> This is a particularly problematic consideration when it comes to Synergy's ability to assign elements of its ETACs to third parties as any assignment from a state government backed entity to a third party will be grounds for WP to refuse consent to assignment because such an assignment would necessarily involve a diminution in credit worthiness. It is the concept of an increase in risk as opposed to simply a demonstration of ability to perform the contract that, in Synergy's view, means the proposed clause is unusual from a commercial point of view.

[748] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, p. 268.

[749] Synergy, *Economic Regulation Authority draft decision on proposed revisions to the access arrangement fort the Western Power network*, June 2018, p. 47.

> Synergy considers an alternative position that emphasises instead the capacity of a proposed counterparty to have the technical and financial capacity to perform its obligations under the contract would better achieve the Access Code objective of increasing competition in upstream and downstream markets. Accordingly Synergy requests the ERA to make a determination on the matter.

2945. Assignment from a State government-backed entity to a third party would necessarily involve a diminution in credit worthiness. However, that is not to say that the third party cannot in any event satisfy the financial and technical capabilities required to meet the obligations for the assigned access rights. The proposed drafting is consistent with clause 5.20 of the Access Code because Western Power is only permitted to withhold consent if in its "reasonable" opinion there is a “financial or technical risk”. This language mirrors the requirement in clause 5.20(a) of the Access Code that permits consent to be withheld where there are “reasonable commercial or technical grounds”.

Relocations (clause 6)

2946. Western Power proposed several changes to clause 6 of the transfer and relocation policy, which covers the provisions for the relocation of contracted capacity.

Clause 6.1

2947. A drafting change to clause 6.1 to clarify the meaning of “relocation” was proposed:

> 6.1 Occurrence of relocation
>
> A “relocation” occurs when a user:
>
> a. decreases its contracted capacity at a connection point (a “retiring point”); and
>
> b. makes a corresponding increase in its contracted capacity at another connection point under the user’s access contract (a “destination point”).

2948. Western Power stated the change was to make clear that a relocation occurs when the user decreases its contracted capacity at a connection point (a “retiring point”); and makes a corresponding increase in its contracted capacity at another connection point (a “destination point”) *under the user’s access contract*.

2949. No submissions on Western Power’s initial proposal addressed the proposed change to clause 6.1.

2950. In the draft decision, the change to clause 6.1 was considered an administrative drafting change, which makes clear that a relocation involves the user moving capacity from one connection point (the “retiring point”) to another connection point (the “destination point”) under its access contract. The change did not materially alter the meaning of the clause.

2951. Western Power’s revised proposal does not readdress this matter and no submissions were received from other interested parties in response to the ERA’s draft decision. On that basis, the ERA maintains its draft decision as set out in paragraph 2950 above.

New clause 6.4

2952. A new clause (6.4) was proposed for the transfer and relocation policy to set out the circumstances and conditions for the consent of relocations:

6.4 Consent

a. A relocation may not be made where it would impede the ability of Western Power to provide a covered service sought in an access application.

b. A relocation is conditional upon the user obtaining the consent of Western Power, which consent Western Power may withhold on reasonable commercial or technical grounds and which consent may be subject to conditions required on reasonable commercial and technical grounds.

c. Without limiting the conditions Western Power may impose, on reasonable commercial or technical grounds, as a condition of consent those conditions 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.

2953. Western Power stated the purpose of the new clause was "to better link the transfer and relocation policy to the provisions of the Access Code, specifically [sections] 5.21 to 5.23".[750]

2954. Synergy submitted additional amendments should be made to the proposed new clause to make the drafting more accurately reflect the provisions of the Access Code. A requirement for Western Power to provide the user with an explanation of the commercial or technical grounds that consent is withheld was also to be added. Synergy's suggested drafting amendments were as follows:

6.4 Consent

a. Western Power:

i. must withhold its consent to a~~A~~ relocation ~~may not be made~~ where it would impede the ability of Western Power to provide a covered service sought in an access application;~~.~~

ii~~b~~. may only withhold its consent to a~~A~~ relocation ~~is conditional upon the user obtaining the consent of Western Power, which consent Western Power may withhold~~ on reasonable commercial or technical grounds and that~~which~~ consent may be subject to conditions only to the extent that they are ~~required on~~ reasonable on commercial and technical grounds, in which case Western Power must provide the user on the user's written request with a detailed explanation of such commercial and technical grounds.

b~~c~~. Without limiting the conditions Western Power may impose, on reasonable commercial or technical grounds, as a condition of consent those conditions 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.

2955. The ERA considered Western Power's proposed new clause and Synergy's suggested amendments to the clause. While Western Power's proposed new clause was substantially consistent with the provisions of the Access Code, the drafting of the clause could have been improved. A requirement for Western Power to provide the user with a written explanation of the commercial and/or technical grounds on which consent was being withheld or the conditions imposed was reasonable. Such an explanation would allow the user to address the commercial and/or technical grounds that are causing consent to be withheld or the conditions imposed.

[750] Western Power, *Access arrangement information: Attachment 12.6*, 2 October 2017, p. 7.

2956. For the reasons above, the ERA required that clause 6.4 of the transfer and relocation policy be amended to read:

> 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.

2957. In its draft decision the ERA required the following amendment to Western Power's proposal.

> **Draft Decision Required Amendment 91**
>
> Clause 6.4 of the transfer and relocation policy must be amended in accordance with paragraph 1840 of this draft decision [paragraph 2956 above].

2958. In its revised proposal, Western Power has accepted draft decision required amendment 91 in principle with modifications.[751]

> 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.
>
> 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.
>
> 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:

[751] Western Power, Revised AA4 proposal: Response to the ERA's draft decision, 14 June 2018, pp. 268-269.

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.

2959. Western Power's additional proposed amendments are not necessary. Section 5.22 of the Code sets out when Western Power must and may withhold consent. Western Power's amendments seek to interpret the Code and add another criterion where an existing covered service is impeded. Although this may fall under the commercial/technical grounds included in section 5.22(b) of the Access Code, specifying it in the manner Western Power proposes could result in unintended consequences. On that basis, the ERA considers Western Power's further proposed amendments to clause 6.4 are not consistent with section 5.22 of the Access Code and must be amended in accordance with the wording in paragraph 2958 above.

Required Amendment 66

The proposed insertion of the words "or continue to provide an existing covered service to an existing user" in clause 6.4 (a)(i) and "by Western Power to withhold its consent or impose conditions" in clause 6.4 (c) must be deleted from clause 6.4 of the Transfer and Relocation Policy.

New clause 6.5

2960. A new clause (6.5) was proposed for the transfer and relocation policy to make clear that a relocation is subject to capacity being available at the connection point:

6.5 Process for Relocation

a. Nothing in this clause 6 limits the requirements of the applications and queuing policy.

b. Without limiting clauses 6.2 and 6.3, the user must also, as part of requesting a relocation, if required by the applications and queuing policy, apply for approval of the relocation. Any such application will be processed in accordance with the applications and queuing policy and the user's access contract.

2961. In its initial proposal, Western Power submitted that:[752]

> A relocation may only occur, without jeopardising system integrity and the rights of other users, if there is capacity available at the new point. Where there are multiple requests to use capacity, priority is determined in accordance with the Applications and Queuing Policy. Relocations are therefore subject to that policy.

2962. In its submission on Western Power's initial proposal, Synergy did not agree with the proposed new clause 6.5 or Western Power's rationale for introducing it. Synergy submitted the following:[753]

> Synergy accepts there may be circumstances where some users will be required to make an application under the applications and queuing policy in connection with a relocation under the [transfer and relocation policy]. However, section 5.22(a) of the Access Code makes it clear Western Power can withhold consent in circumstances where a relocation would impede the ability of Western Power to provide a covered service that is sought in an access application.
>
> In such circumstances an application under the applications and queuing policy will be required, but Synergy considers this would be the only occasion in respect of which such an application would be required.
>
> Further, the Access Code provisions that set out the requirement for the contents of the [transfer and relocation policy] are exhaustive rather than permissive, in which sense they do not entitle Western Power to use the [transfer and relocation policy] to expand the scope of the applications and queuing policy. In Synergy's view, while there is the potential for cross-over as described [above], the applications and queuing policy and the [transfer and relocation policy] are, and must remain, distinct. This is because the [transfer and relocation policy] deals with capacity decreases and relocations while the applications and queuing policy deals with the assessment of plant and equipment to connect to Western Power's network, assess connection applications and make network access offers.

2963. The applications and queuing policy is required by the Access Code and is a policy setting out the access application process for customers seeking access to the Western Power Network. Proposed amendments to this policy were considered elsewhere in the draft decision.

2964. Given the constrained nature of the Western Power Network, relocations can only occur where there is available capacity at the destination point. Where capacity is unavailable, or there are multiple requests for capacity at a particular connection point and where there is an existing access application for that connection point, Western Power must consider its applications and queuing policy to process the relocation request(s). The proposed new clause 6.5 reflected the process and procedures Western Power wast to consider when accessing a relocation request.

2965. Western Power's revised proposal does not readdress this matter and no submissions were received from other interested parties in response to the ERA's draft decision. On that basis, the ERA maintains its draft decision.

[752] Western Power, *Access arrangement information: Attachment 12.6*, 2 October 2017, p. 8.

[753] Synergy, *AA4 Submission Number 1: Western Power's proposed transfer and relocation policy*, 8 December 2017, p. 11, paragraphs 40-44.

Other amendments

2966. Other amendments to the transfer and relocation policy were proposed, including amendments to some defined terms (assignee, assignor and connection point) for clarity and administrative drafting changes to correct drafting errors.[754]

2967. In its draft decision, the ERA gave consideration to the defined terms in the transfer and relocation policy that have different meanings to the same terms used in the Access Code (refer to paragraph 2919 above). Subject to the ERA's considerations of these defined terms, the other proposed amendments were considered minor in nature and did not materially alter the transfer and relocation policy.

2968. Western Power's revised proposal does not include further amendments, other than those discussed above and some minor formatting and cross referencing corrections.

[754] These amendments are shown in the marked-up version the transfer and relocation policy provided with the initial proposed access arrangement (at Appendix D).

APPENDICES

Appendix 1 Summary of Required Amendments

Required Amendment 1

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.

Include a correction factor for under or over-recovery of the TEC for prior periods.

Required Amendment 2

Clause 5.12 must be amended to state that charges for metering extended services must also comply with clause 6.6(1)(e) of the *Electricity Industry (Metering) Code 2012*.

Required Amendment 3

Required Amendment 4

Western Power must amend its operating expenditure forecasts to be consistent with the values determined by the ERA in this Final Decision as set out in Table 51 above

Required Amendment 5

Western Power must amend forecast deprecation for AA4 to the values shown in Table 121 above.

The asset life for “other non-network assets” must be amended to 27 years.

The classification of business support expenditure must be amended to allocate expenditure for land to the correct asset category.

Required Amendment 6

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

Required Amendment 7

Western Power must amend the (nominal after-tax) weighted average cost of capital to 5.87 per cent, based on the paraeters set out in Table 129 of this final decision and reasoning detailed in Appendix 5 of this final decision.

Required Amendment 8

The values of smoothed target revenue, forecast new facilities investment, foreast non-capital costs and weighted average cost of capital used to calculate working capital must be adjusted to be consistent with this final decision.

Required Amendment 9

Forecast taxation costs must be updated to be consistent with the final decision and the calculation must be amended to use unsmoothed revenue for each service.

Required Amendment 10

Western Power must update the Investment Adjustment Mechanism value to reflect the ERA’s final decision on AA3 capital expenditure.

Required Amendment 11

Western Power must update the Gain Share Mechanism to reflect the ERA's final decision on wood pole expenditure and unforeseen events.

Required Amendment 12

Western Power must adjust target revenue to remove its proposed unforeseen event adjustment.

Required Amendment 13

Western Power must reinstate its proposed residential and business time of use based demand services in its proposed reference services.

Required Amendment 14

The new time of use services must be available to users with existing interval capable meters.

Western Power must amend the peak period for the existing residential and business time of use services (A3, A4, C3 and C4) to be consistent with the peak and shoulder periods used in its proposed new residential and business time of use services (D1 and D2) and 7am-3pm should be classified as a shoulder period.

Required Amendment 15

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. As a minimum this should include:

- An accumulation meter manual read every two months
- An interval meter manual read with data provided every two months
- An interval meter manual read with data provided every month
- A one-off interval meter manual read
- An interval meter read remote read daily

Required Amendment 16

Western Power must include reference services that meet the services listed in paragraph 1202 of the final decision or identify how existing reference services can be utilised to enable users to obtain these services.

Required Amendment 17

Western Power must revise the changes to metering definitions and conditions (including new clause 1.4 and Annexure A) in Appendix E Reference Services, to be consistent with required amendment 15.

Required Amendment 18

Western Power must amend the eligibility criteria for reference services by adding a definition of "materially different" that provides sufficient clarity and certainty to users with access contracts that they will be able to continue to use reference services during AA4 under their existing contracts.

Required Amendment 19

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 final decision and apply them from a commencement date of 1 February 2019. Western Power must also amend the 2018/19 Price List and Price List Information for other relevant changes in the final decision on reference services and tariff structures as set out in Pricing Methods, Price List and Price List Information.

Required Amendment 20

Western Power must amend the 2018/19 Price List and Price List Information to include tables similar to those provided for distribution tariffs, to demonstrate that transmission tariffs are set between the incremental and stand-alone costs of service provision and that the variable components of transmission tariffs recover the incremental costs of service provision.

Required Amendment 21

Western Power must amend the side constraint formula to remove the correction factor for under or over recovery of target revenue from prior periods.

Required Amendment 22

Western Power must include distribution connected users with demand greater than 7,000 kVA in the class of users charged the TEC.

Required Amendment 23

Western Power must develop tariffs compliant with the Code requirements and include supporting information on how the costs have been derived and the basis of the tariffs in its price list information and price list for the metering services required by the ERA in Reference Services and Non-Reference Services.

Required Amendment 24

Western Power must provide sufficient information in the Price List Information to enable users to understand (and provide evidence for) the differential rates for the D1 and D2 services. This should also include sufficient information to enable users to understand whether, and if so how, these differential rates may change in the future.

Required Amendment 25

Western Power must amend the RT5 and RT6 tariffs to include a mechanism that adjusts the rolling 12-month maximum half-hourly demand where it can be clearly demonstrated that future demand will be lower.

Required Amendment 26

Western Power must include in the price list information specific cost information to demonstrate the level of the proposed Excess Network Usage Charges is based on the forward-looking efficient costs from a user exceeding its contracted capacity and that the factors applied for different geographical areas are consistent with the Access Code requirement that charges paid by different users of the reference service only differ to the extent necessary to reflect differences in the average cost of service provision.

Required Amendment 27

Western Power must amend the Price List and Price List Information to include the required new reference services.

Required Amendment 28

Western Power must discontinue reporting the system minutes interrupted (radial and meshed) performance measures as service standard benchmarks.

Required Amendment 29

Western Power must make clear the classification of 220kV circuits between Muja Terminal and Merredin Terminal, and report disaggregated loss of supply event frequency performance measures for radial and meshed circuits. Western Power is not required to set service standard benchmark for the radial and meshed elements of the loss of supply event frequency performance measures.

Required Amendment 30

Western Power must amend the definition of "System Peak MW" within the loss of supply event frequency formula as follows:

"System Peak MW" is the maximum peak demand recorded on the South West Interconnected System for the previous financial year, excluding the coincident demand of customers directly connected to the transmission system and receiving a non-reference service.

Required Amendment 31

Western Power must use the single probability distribution of best fit to derive service standard benchmarks.

Required Amendment 32

Western Power must derive service standard benchmarks at the 97.5th percentile of the single probability distribution of best fit for SAIDI, SAIFI loss of supply event frequency and average outage duration performance measures, and at the 2.5th percentile for call centre performance and circuit availability performance measures.

Required Amendment 33

Western Power must record and report momentary interruption events, consistent with the proposed $MAIFI_e$ formula, within the annual Service Standard Performance Report during the fourth access arrangement period, for the purpose of establishing service standard benchmarks and targets in the next access arrangement period.

Required Amendment 34

Western Power must record and report momentary interruption events by feeder category within the Service Standard Performance Report during the fourth access arrangement period.

Required Amendment 35

Western Power must remove zone substation transformers from the list of exclusions for the circuit availability and average outage duration performance measures.

Required Amendment 36

Metering expenditure must be removed from the investment adjustment mechanism.

Required Amendment 37

Section 7.4.3 of the proposed revised access arrangement must be amended to specify that an adjustment, based on the proportion of years with service standard benchmark failures over the access arrangement period, will be made to the total above-benchmark surplus.

Required Amendment 38

Western Power must delete proposed new section 7.4.2 and the following tables from the proposed revised access arrangement:

- Table 32: Efficiency and innovation benchmarks for the transmission system.
- Table 33: Efficiency and innovation benchmarks for the distribution system.

Western Power must include a single table with efficiency and innovation benchmarks for the total business consistent with the ERA's determination of efficient operating costs.

Required Amendment 39

Western Power must amend the efficiency and innovation benchmarks to be consistent with the final decision on operating expenditure.

Required Amendment 40

Western Power must set service standard targets for the financial years from 2018/19 to 2021/22 at the average annual level of performance achieved in the third access arrangement period, adjusted for anticipated changes in service reliability and where individual penalty caps have been applied during the third access arrangement period, as shown in Table 177.

Required Amendment 41

Western Power must apply the revised weightings of values of customer reliability to SAIDI and SAIFI incentive rates listed in

Table 180.

Required Amendment 42

Western Power must set revenue-at-risk caps as follows:

Required Amendment 43

Western Power must allocate revenue-at-risk to the performance measures on the transmission network at the rates shown in Table 182.

Required Amendment 44

Western Power must delete proposed new sections 7.6.6 to 7.6.10 from the access arrangement.

Required Amendment 45

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 proposed clauses 3.1(d) to (g) must be deleted.

Required Amendment 46

Clause 13(e) of the electricity transfer access contract must read:

"Notwithstanding clause 13(d) 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)."

Required Amendment 47

Clause 13(c)(ii)(A) of the electricity transfer access contract must be amended so the notification period is at least 45 days prior to the modification being made.

Required Amendment 48

Clause 13(f) of the electricity transfer access contract must be amended so the notification period is at least 45 days prior to the modifications being made.

Required Amendment 49

The definition of material change in schedule 1 of the electricity transfer access contract must be amended to reflect the wording in paragraph 2286.

Required Amendment 50

Clause 19.11(a) of the electricity transfer access contract must be amended in accordance with paragraph 2303 of this final decision.

Required Amendment 51

Clause 22.3(a) of the electricity transfer access contract must be amended to read:

"A notice under clause 22.3(a) must be given as soon as reasonably practicable and in any event within 5 Business Days of a Party becoming aware an event is or is likely to be a Force Majeure Event."

Required Amendment 52

The provisions for dormant applications must be amended to ensure applications cannot be deemed dormant if they are less than three years old or the lack of progress is due to Western Power not progressing the application.

Required Amendment 53

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.

Required Amendment 54

Western Power must ensure there is a mechanism for refunding to the CAG applicant any amount of processing fees paid in excess of the contribution payable.

Required Amendment 55

Western Power must ensure there is a mechanism for refunding to the CAG applicant amounts of the processing fees in excess of the contribution payable.

Required Amendment 56

Clause 16.3 must be amended as follows:

"… as a reasonable and prudent person, and acting in accordance with good electricity industry practice, …"

Required Amendment 57

Western Power's proposed amendments to clauses 3.8 and 14.5 of the applications and queuing policy must be deleted.

Required Amendment 58

Western Power's proposed amendments to clauses 10.2(a), 16.2(a), 16.3 and 16.4 (as set out in paragraph 2639 above, must be deleted.

Required Amendment 59

Western Power's proposed amendments to clause 6.2(a) to add the market operator and system management must be deleted.

Required Amendment 60

Clause 24.9(d) of the applications and queuing policy must be amended in accordance with paragraph 2683 above of this final 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

Required Amendment 61

Western Power must retain Figure 1 ("Access, Connection and Transfer Applications Policy – Process Overview") and the tables headed "Primary Information provided to applicants by Western Power" and "How the Competing Applications Groups (CAGs) will be managed." Western Power must ensure the information in the flowchart and tables is consistent with the relevant clauses of the applications and queuing policy.

Required Amendment 62

Required Amendment 63

The “a” before “security” in clauses 4.3(a) and 4.3(c) of the Contributions Policy must be deleted.

Required Amendment 64

Section 2.2 of the DLVCHS must be amended to state prices are reviewed at least once every 12 months.

The proposed insertion of the words “at least” into the first paragraph of section 5.1 of the proposed Contributions Policy Appendix C.2 should be deleted.

Required Amendment 65

The proposed insertion of the words “over the same period over which connections are modelled under clause 5.1” into subclause 6(a) of the proposed Contributions Policy Appendix C.2 should be deleted and the words “in the last twelve months” must be retained..

Required Amendment 66

The proposed insertion of the words “or continue to provide an existing covered service to an existing user” in clause 6.4 (a)(i) and “by Western Power to withhold its consent or impose conditions” in clause 6.4 (c) must be deleted from clause 6.4 of the Transfer and Relocation Policy.

Appendix 2 Glossary

AA1	first access arrangement period
AA2	second access arrangement period
AA3	third access arrangement period
AA4	fourth access arrangement period
AA5	fifth access arrangement period
AAI	access arrangement information
AASB	Australian Accounting Standards Board
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Akaike information criterion
AMI	advanced metering infrastructure
AOD	average outage duration
AQP	Applications and Queuing Policy
ATMD	any time maximum demand
ATO	Australian Tax Office
AWOTE	average weekly ordinary time earnings
BTM	behind the metre
CAG	competing applications group
CBD	central business district
CESS	capital expenditure sharing scheme
CMD	contract maximum demand
CPI	consumer price index
DLVCHS	distribution low voltage connection headworks scheme
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DNSPs	distribution service network providers

EBSS	efficiency benchmark service standard
EGWWS	electricity, gas, water and wastewater services
EIB	efficiency innovation benchmark
EMR	electricity market review
ENUC	excess network usage charges
ERA	Economic Regulation Authority
ESC	Essential Service Commission Victoria
ETAC	Electricity Transfer Access Contract
EV	electric vehicles
GIA	generator interim access
GSM	gain sharing mechanism
GST	goods and services tax
GWh	giga watt hours
HR	human resources
HV	high voltage
IAM	investment adjustment mechanism
ICT	information communications and technology
IEAust	Institute of Engineers Australia
IEEE	Institute of Electrical and Electronic Engineers
IMO	Independent Market Operator
IT	information technology
kV	kilo volts
kVa	kilo volt amps
kWh	kilo watt hours
LEDs	light emitting diodes
MAIFI	momentary average interruption frequency index
MED	major event days
MW	mega watts
MWh	mega watt hours

MTR	multiple trading relationships
NEM	national electricity market
NFIT	new facilities investment test
NMI	national market identifier
NOI	notice of intention
NPV	net present value
NQRS	network quality and reliability of supply
NSP	network service provider
ODP	optimised deprival value
PAO	preliminary access offer
POE 10	probability of exceedance 10%
POE 50	probability of exceedance 50%
PV	photovoltaic
PUO	Public Utilities Office
Q-Q	quantile-quantile
RAB	regulated asset base
RCM	reserve capacity mechanism
RT [x]	reference tariff [x]
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
SSD	service standard difference
SST	standard service target
STPIS	service target and performance incentive scheme
SUPP	state underground power program
SWIN	south west interconnected network

SWIS	south west interconnected system
TEC	tariff equalisation contribution
TNSPs	transmission network service providers
WA	Western Australia
WACC	weighted average cost of capital
WACOSS	Western Australian Council of Social Services
WALGA	Western Australian Local Government Authority
WEM	wholesale electricity market
WP	Western Power
WPI	wage price Index

Appendix 3 Public Submissions

The following submissions were received by the ERA in response to the invitation for submissions (notice) published on 25 May 2018. These submissions are published on the ERA's website.

ATCO Australia
Australian Energy Council
Australian Energy Market Operator
Department of Treasury – Public Utilities Office
Energy Networks Australia
Horizon Power
Moore River Company
Mr Stephen Davidson
Perth Energy
Power Ledger
Summit Southern Cross Power Holdings Pty Ltd
Synergy
Urban Development Institute of Australia
Vector Limited
WA Major Energy Users
Western Australian Local Government Association

Appendix 4 Revenue model

This Appendix is published as a separate publication on the ERA's website.

The revenue model sets out the ERA's calculation of the target revenue and, in the event of inconsistency, the numbers in the revenue model prevail over any other statement of these values in this decision.

Appendix 5 Return on regulated capital base

This Appendix is published as a separate publication on the ERA's website.

Appendix 6 GHD Advisory revised technical review of Western Power’s proposed access arrangement

This Appendix is published as a separate publication on the ERA’s website.

Appendix 7 Geoff Brown and Associates revised technical review of Western Power's proposed access arrangement

This Appendix is published as a separate publication on the ERA's website.